STATE OF ILLINOIS
ILLINOIS COMMERCE COMMISSION

Ameren Illinois Company d/b/a Ameren Illinois Approval of the Energy Efficiency and Demand-Response Plan pursuant to 220 ILCS 5/8-103 and 220 ILCS 5/8-104.	:	Docket No. 13-0498

INITIAL BRIEF OF THE STAFF
OF THE ILLINOIS COMMERCE COMMISSION

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Staff of the Illinois Commerce Commission ("Staff"), by and through its undersigned counsel, pursuant to Section 200.800 of the Illinois Commerce Commission's ("Commission" or "ICC") Rules of Practice (83 Ill. Adm. Code 200.800), respectfully submits its Initial Brief in the instant proceeding.

I. INTRODUCTION

The Ameren Illinois Company's ("AIC" or "Ameren" or "Company") integrated electric and natural gas energy efficiency ("EE") Plan ("Plan" or "Plan 3") (Ameren Ex. 6.1; Ameren Ex. 7.2; Ameren Ex. 1.1 (2nd Rev.) and Appendices A through D) is required by Sections 8-103, 8-103A, and 8-104 of the Illinois Public Utilities Act ("Act") to include certain key elements in order to be approved by the Commission.

Staff witness Jennifer L. Hinman provided Staff's fact-based assessment of whether the Company has made the required showings per the requirements set forth in Sections 8-103(f)(1)-(7), 8-103(g), 8-103A, 8-104(f)(1)-(8), 8-104(g) and the

Commission-adopted IL-TRM Policy Document. (*See generally,* Staff Ex. 1.0.) This Initial Brief will provide Staff's legal assessment of whether the Company has made the required showings per the requirements set forth in Sections 8-103(f)(1)-(7), 8-103(g), 8-103A, 8-104(f)(1)-(8), 8-104(g) and the Commission-adopted IL-TRM Policy Document. This brief will also summarize Staff's recommendations on the Company's Plan and provide comment on other parties' recommendations.

II. STATUTORY LANGUAGE

With respect to the electric portion of the Plan, the Act states:

> In submitting proposed energy efficiency and demand-response plans and funding levels to meet the savings goals adopted by this Act the utility shall:
>
> (1) Demonstrate that its proposed energy efficiency and demand-response measures will achieve the requirements that are identified in subsections (b) and (c) of this Section, as modified by subsections (d) and (e).
>
> (2) Present specific proposals to implement new building and appliance standards that have been placed into effect.
>
> (3) Present estimates of the total amount paid for electric service expressed on a per kilowatthour basis associated with the proposed portfolio of measures designed to meet the requirements that are identified in subsections (b) and (c) of this Section, as modified by subsections (d) and (e).
>
> (4) Coordinate with the [Illinois] Department [of Commerce and Economic Opportunity ("DCEO" or "Department")] to present a portfolio of energy efficiency measures proportionate to the share of total annual utility revenues in Illinois from households at or below 150% of the poverty level. The energy efficiency programs shall be targeted to households with incomes at or below 80% of area median income.
>
> (5) Demonstrate that its overall portfolio of energy efficiency and demand-response measures, not including programs covered by item (4) of this subsection (f), are cost-effective using the total resource cost test and

> represent a diverse cross-section of opportunities for customers of all rate classes to participate in the programs.
>
> (6) Include a proposed cost-recovery tariff mechanism to fund the proposed energy efficiency and demand-response measures and to ensure the recovery of the prudently and reasonably incurred costs of Commission-approved programs.
>
> (7) Provide for an annual independent evaluation of the performance of the cost-effectiveness of the utility's portfolio of measures and the Department's portfolio of measures, as well as a full review of the 3-year results of the broader net program impacts and, to the extent practical, for adjustment of the measures on a going-forward basis as a result of the evaluations. The resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given year.

220 ILCS 5/8-103(f). The Act also provides that:

> No more than 3% of energy efficiency and demand-response program revenue may be allocated for demonstration of breakthrough equipment and devices.

220 ILCS 5/8-103(g).

An additional analysis is required for the 2013 submission of the electric Plan. Section 8-103A states:

> Beginning in 2013, an electric utility subject to the requirements of Section 8-103 of this Act shall include in its energy efficiency and demand-response plan submitted pursuant to subsection (f) of Section 8-103 an analysis of additional cost-effective energy efficiency measures that could be implemented, by customer class, absent the limitations set forth in subsection (d) of Section 8-103. In seeking public comment on the electric utility's plan pursuant to subsection (f) of Section 8-103, the Commission shall include, beginning in 2013, the assessment of additional cost-effective energy efficiency measures submitted pursuant to this Section. For purposes of this Section, the term "energy efficiency" shall have the meaning set forth in Section 1-10 of the Illinois Power Agency Act, and the term "cost-effective" shall have the meaning set forth in subsection (a) of Section 8-103 of this Act.

220 ILCS 5/8-103A.

The Illinois Power Agency Act ("IPA Act") provides the definitions for demand-response, energy efficiency, and the total resource cost test ("TRC test"):

> "Demand-response" means measures that decrease peak electricity demand or shift demand from peak to off-peak periods.
>
> ….
>
> "Energy efficiency" means measures that reduce the amount of electricity or natural gas required to achieve a given end use. "Energy efficiency" also includes measures that reduce the total Btus of electricity and natural gas needed to meet the end use or uses.
>
> ….
>
> "Total resource cost test" or "TRC test" means a standard that is met if, for an investment in energy efficiency or demand-response measures, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the program to the net present value of the total costs as calculated over the lifetime of the measures. A total resource cost test compares the sum of avoided electric utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided natural gas utility costs, to the sum of all incremental costs of end-use measures that are implemented due to the program (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side program, to quantify the net savings obtained by substituting the demand-side program for supply resources. In calculating avoided costs of power and energy that an electric utility would otherwise have had to acquire, reasonable estimates shall be included of financial costs likely to be imposed by future regulations and legislation on emissions of greenhouse gases.

20 ILCS 3855/1-10. With respect to the gas portion of the portfolio, Section 8-104(b) of the Act states:

> "[C]ost-effective" means that the measures satisfy the total resource cost test which, for purposes of this Section, means a standard that is met if, for an investment in energy efficiency, the benefit-cost ratio is greater than one. The benefit-cost ratio is the ratio of the net present value of the total benefits of the measures to the net present value of the total costs as calculated over the lifetime of the measures. The total resource cost test compares the sum

> of avoided natural gas utility costs, representing the benefits that accrue to the system and the participant in the delivery of those efficiency measures, as well as other quantifiable societal benefits, including avoided electric utility costs, to the sum of all incremental costs of end use measures (including both utility and participant contributions), plus costs to administer, deliver, and evaluate each demand-side measure, to quantify the net savings obtained by substituting demand-side measures for supply resources. In calculating avoided costs, reasonable estimates shall be included for financial costs likely to be imposed by future regulation of emissions of greenhouse gases. The low-income programs described in item (4) of subsection (f) of this Section shall not be required to meet the total resource cost test.

220 ILCS 5/8-104(b).

With respect to the gas portion of the Plan, Section 8-104(f) of the Act requires:

> In submitting proposed energy efficiency plans and funding levels to meet the savings goals adopted by this Act the utility shall:
>
> (1) Demonstrate that its proposed energy efficiency measures will achieve the requirements that are identified in subsection (c) of this Section, as modified by subsection (d) of this Section.
>
> (2) Present specific proposals to implement new building and appliance standards that have been placed into effect.
>
> (3) Present estimates of the total amount paid for gas service expressed on a per therm basis associated with the proposed portfolio of measures designed to meet the requirements that are identified in subsection (c) of this Section, as modified by subsection (d) of this Section.
>
> (4) Coordinate with the Department to present a portfolio of energy efficiency measures proportionate to the share of total annual utility revenues in Illinois from households at or below 150% of the poverty level. Such programs shall be targeted to households with incomes at or below 80% of area median income.
>
> (5) Demonstrate that its overall portfolio of energy efficiency measures, not including programs covered by item (4) of this subsection (f), are cost-effective using the total resource cost test and represent a diverse cross section of opportunities for customers of all rate classes to participate in the programs.

> (6) Demonstrate that a gas utility affiliated with an electric utility that is required to comply with Section 8-103 of this Act has integrated gas and electric efficiency measures into a single program that reduces program or participant costs and appropriately allocates costs to gas and electric ratepayers. The Department shall integrate all gas and electric programs it delivers in any such utilities' service territories, unless the Department can show that integration is not feasible or appropriate.
>
> (7) Include a proposed cost recovery tariff mechanism to fund the proposed energy efficiency measures and to ensure the recovery of the prudently and reasonably incurred costs of Commission-approved programs.
>
> (8) Provide for quarterly status reports tracking implementation of and expenditures for the utility's portfolio of measures and the Department's portfolio of measures, an annual independent review, and a full independent evaluation of the 3-year results of the performance and the cost-effectiveness of the utility's and Department's portfolios of measures and broader net program impacts and, to the extent practical, for adjustment of the measures on a going forward basis as a result of the evaluations. The resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given 3-year period.

220 ILCS 5/8-104(f). The Act further provides that:

> No more than 3% of expenditures on energy efficiency measures may be allocated for demonstration of breakthrough equipment and devices.

220 ILCS 5/8-104(g).

III. PROCEDURAL HISTORY

On August 30, 2013, Ameren filed its Verified Petition for Approval of its Integrated Electric and Natural Gas Energy Efficiency Plan as well as testimony. The following parties intervened: the Environmental Law and Policy Center ("ELPC"), the Citizens Utility Board ("CUB"), the Natural Resources Defense Council ("NRDC"), the People of the State of Illinois ("AG"), the Illinois Industrial Energy Consumers ("IIEC") and Comverge, Inc. On October 18, 2013, Staff and Intervenors filed Direct Testimony.

On October 28, 2013, Staff and Intervenors filed Rebuttal Testimony in response to each others' Direct Testimony. On November 14, 2013, Ameren filed Rebuttal Testimony.

At an evidentiary hearing on November 20, 2013, witnesses testified and were cross examined, and evidence was entered into the record. Pursuant to the schedule entered by the Administrative Law Judge on September 16, 2013 (Tr. 7), this Initial Brief follows.

IV. ELECTRIC AND GAS SAVINGS GOALS AND SPENDING LIMITS

A. PROPOSED MODIFIED GOALS

1. Explanation of Proposed Modified Goals

(a) Proposed Electric Goals

Pursuant to Section 8-103(f)(1) of the Act, the Company's Plan must demonstrate that its proposed EE and demand-response measures will achieve the requirements that are identified in subsections (b) and (c) of Section 8-103, as modified by subsections (d) and (e) of that Section. 220 ILCS 5/8-103(f)(1). The Company proposes to modify the savings goals set forth in Section 8-103(b). (Ameren Ex. 6.0, 3; Ameren Ex. 6.1, 61.) Specifically, excluding the DCEO portion of the portfolio, AIC proposes the following utility-specific modified energy savings goals in rebuttal testimony: 195,958 MWh (EPY7), 203,018 MWh (EPY8), and 209,393 MWh (EPY9), for a cumulative 3-year modified savings goal of 608,369 MWh (Plan 3). (Ameren Ex. 6.1, 6.)

(b) Proposed Gas Goals

Pursuant to Section 8-104(f)(1) of the Act, the Company's Plan must demonstrate that its proposed EE measures will achieve the requirements that are identified in subsection (c) of Section 8-104 of the Act, as modified by subsection (d) of that Section. 220 ILCS 5/8-104(f)(1). AIC proposes to modify the energy savings goals set forth in Section 8-104(c) of the Act. (Ameren Ex. 6.0, 3; Ameren Ex. 6.1, 61; Ameren Ex. 1.1 (2nd Rev.), 5-6.) Specifically, excluding the DCEO portion of the portfolio, the Company proposes the following AIC-specific modified energy savings goals in rebuttal testimony: 4,540,780 therms (GPY4), 4,537,295 therms (GPY5), and 4,533,822 therms (GPY6), for a cumulative 3-year modified savings goal of 13,611,898 therms. (Ameren Ex. 6.1, 6.)

2. Adequacy of Savings Goals

Staff supports the concept of modifying the statutory electric and gas savings goals. Given the low market prices for electricity and natural gas, there are few cost-effective measures available. (Staff Ex. 1.0, 17; Staff Ex. 2.0, 21.) The lower gas and electricity prices also reduce the budget available for the EE portfolio. Id. Low energy prices reduce incentives for customers to participate in EE programs. (Staff Ex. 1.0, 17.) All of these factors contribute to the difficulty in meeting the unmodified energy savings goals and therefore Staff supports the concept of modifying the goals. (Staff Ex. 1.0, 15-16; Staff Ex. 2.0, 21.)

B. Electric and Gas Spending Limits

1. Proposed Electric Spending Limit

Notwithstanding the requirements of Sections 8-103(b) and (c) of the Act, Section 8-103(d) requires reductions to the amount of EE and demand response measures implemented over a 3-year planning period by an amount necessary to limit the estimated average annual increase in the amounts paid by retail customers in connection with electric service due to the cost of those measures by certain specific percentages. 220 ILCS 5/8-103(d). Specifically, during Plan 3, the estimated average net increase is limited to no more than the greater of 2.015% of the amount paid per kilowatt-hour ("kWh") by those customers during the year ending May 31, 2007 or the incremental amount per kWh paid for these measures in 2011. (Staff Ex. 1.0, 12-13.) Thus, the electric spending limit for each electric program year of Plan 3 is the incremental amount per kWh paid for these measures in 2011 (0.1543¢/kWh) multiplied by the forecasted energy deliveries for each program year which are adjusted for load reductions due to energy efficiency measures. (Staff Ex. 1.0, 13.)

The Commission should approve AIC's calculated dollar amount for the electric spending limits for Plan 3: $59,586,934 (EPY7), $60,551,052 (EPY8), and $60,879,122 (EPY9). (Staff Ex. 1.0, 13-14.) Allocating 75% of the spending limit to AIC as required under Section 8-103(e), the Commission should approve AIC's budget over Plan 3 as the following: $44,690,200 (EPY7), $45,413,289 (EPY8), and $45,659,342 (EPY9). (Ameren Ex. 6.1, 6; Ameren Ex. 1.1 (2nd Rev.), 6; Ameren Ex. 9.0, 2; Ameren Ex. 9.2, 1; Staff Ex. 1.0, 14; Staff Group Cross Ex. 2, 1.)

2. Proposed Gas Spending Limit

Notwithstanding the requirements of subsection (c) of Section 8-104 of the Act, Section 8-104(d) provides that a natural gas utility shall limit the amount of EE implemented in any 3-year reporting period established by subsection (c) of Section 8-104 of the Act, by an amount necessary to limit the estimated average increase in the amounts paid by retail customers in connection with natural gas service to no more than 2% in the applicable 3-year reporting period. 220 ILCS 5/8-104(d). Specifically, Section 8-104(d) states that "[t]he energy savings requirements in subsection (c) of this Section may be reduced by the Commission for the subject plan, if the utility demonstrates by substantial evidence that it is highly unlikely that the requirements could be achieved without exceeding the applicable spending limits in any 3-year reporting period." 220 ILCS 5/8-104(d). AIC reports the gas spending limits to be the following: $15,606,828 for GPY4, $15,662,621 for GPY5, and $15,694,411 for GPY6. (Ameren Ex. 6.1, 4; Ameren Ex. 9.0, 8.)

3. Response to Proposed Spending Limits

The Commission should approve AIC's calculated dollar amount for the electric spending limits for Plan 3: $59,586,934 (EPY7), $60,551,052 (EPY8), and $60,879,122 (EPY9). (Staff Ex. 1.0, 13-14.) The Commission should approve AIC's calculated dollar amount for the gas spending limits for Plan 3: $15,606,828 for GPY4, $15,662,621 for GPY5, and $15,694,411 for GPY6. (Ameren Ex. 6.1, 4; Ameren Ex. 9.0, 8.)

(i) Proposed Spending Requirements

CUB, NRDC, and Staff expressed concern that AIC has failed to spend available funds despite approval of modified savings goals during Plan 2. (NRDC Ex. 1.0, 15-16, 18; CUB Ex. 1.0, 17-18; Staff Ex. 3.0C, 5.) Given modified savings goals are being requested for Plan 3, the Commission should direct AIC to spend all available funding to the extent practicable on cost-effective EE measures. (Staff Ex. 3.0C, 4.) This approach is consistent with the way goals can be satisfied (e.g., banking) and it will benefit customers if AIC exceeds the modified savings goals by pursuing additional cost-effective measures. (Staff Ex. 3.0C, 5.) AIC states that it "will continue to spend available funds, to the extent practicable, in an effort to meet its savings goals and achieve optimal savings without exceeding the spending limits." (Ameren Ex. 6.0, 5.)

In the Plan 2 Order, the Commission directed AIC to spend additional gas funds above those needed to meet the gas goals. The Plan 2 Order states:

> The Commission further directs Ameren to include in its compliance filing, a gas savings plan that encompasses the agreed gas spending limit of $56,621,420 and results in the gas savings espoused by Staff and the AG for Plan 2. The Commission recognizes that the requirements for gas savings during the Plan can be accomplished with excess savings in one year satisfying another year, however the Commission expects Ameren to be mindful of the savings requirements that will be expected in the next Plan.
>
> The Commission also directs Ameren to expend excess funds available in any year that are over and above what Ameren expects to spend on gas savings, to the extent possible, toward joint gas-electric savings opportunities that Ameren can identify. While the Commission recognizes that Ameren alone has authority over how it spends these excess funds so long as they are spent in accordance with the requirements of this Order, the Commission expects Ameren to work with the SAG to identify opportunities. Ameren shall not be required to spend more than 75% of the total natural gas budget. The Commission finds that the expenditure of these funds will not only benefit joint gas-electric customers, recognizing that Ameren is a gas and electric utility, but should enable Ameren to approach its required electric efficiency savings under the Act.

ICC Order Docket No. 10-0568 at 45 (Dec. 21, 2010). For the aforementioned reasons, the Commission should direct AIC to spend all available funding to the extent practicable on cost-effective EE measures. (Staff Ex. 3.0C, 4.)

4. Breakthrough Equipment and Devices

With respect to the electric portion of the Plan, the Act provides that no more than 3% of energy efficiency and demand-response program revenue may be allocated for demonstration of breakthrough equipment and devices. 220 ILCS 5/8-103(g). With respect to the gas portion of the Plan, the Act further provides that no more than 3% of expenditures on energy efficiency measures may be allocated for demonstration of breakthrough equipment and devices. 220 ILCS 5/8-104(g). The Company's Plan asserts that no more than 3% of program revenue has been allocated for demonstration of "breakthrough equipment." (Ameren Ex. 6.1, 14-16; Ameren Ex. 1.1 (2nd Rev.), 14-16.) Staff assumes that AIC's references to "Emerging Technologies" are synonymous with "demonstration of breakthrough equipment and devices" as referenced in Sections 8-103(g) and 8-104(g) of the Act. (*See, e.g.,* Ameren Ex. 1.1 (2nd Rev.), 14-16, 68; Ameren Ex. 2.0, 14.) The Company notes that a codes and standards pilot coordinated with the other Illinois utilities may be funded through this line item. (Ameren Ex. 6.1, 68; Ameren Ex. 1.1 (2nd Rev.), 68.)

The phrase "breakthrough equipment and devices" is not defined in the Act, has not previously been defined by the Commission, and could be open to interpretation. (Staff Ex. 1.0, 25-26.) This ambiguity makes it difficult to determine whether or not the Plan is consistent with the 3% ceiling on such spending as required per Sections 8-103(g) and 8-104(g) of the Act. Therefore, the Commission should define "breakthrough equipment and devices" in this proceeding such that compliance with this statutory standard can be ensured over the course of Plan 3. In particular, the Commission should define "breakthrough equipment and devices" as "measures or programs in their early stage of development that are subject to substantial uncertainty about their cost-effectiveness during the planning period."

Breakthrough technology should not be classified as part of a standard program for reconciliation purposes. Currently, without a clear definition, measures and programs that should fall under breakthrough technology may be classified as part of a standard program for reconciliation purposes as a means to circumvent statutory limitations. (Staff Group Cross Ex. 2, 16-18.) Incentives for breakthrough technology can be offered through a standard program; however, these incentive costs and any other direct costs related to the breakthrough technology should be identified as a separate line item on the reconciliation report. Id.

In Staff's view, to circumvent the statutory limitations means to spend greater than 3% of portfolio resources on breakthrough equipment and devices per Sections 8-103(g) and 8-104(g) of the Act. (Staff Group Cross Ex. 2, 18.) This can occur through misclassifying costs for certain breakthrough equipment and device measures in the reconciliation report as part of the standard program. (Staff Group Cross Ex. 2, 18.)

Staff has concerns about the practice of splitting costs between this cost category and another. If the cost can fall within the definition of breakthrough equipment and devices and some other cost category, then the entire cost should be classified under the category of breakthrough equipment and devices. (Staff Group Cross Ex. 2, 18.)

To the extent a measure proposed in AIC's Plan falls under the definition of "breakthrough equipment and devices" and the participation of this breakthrough equipment and device measure is forecasted in AIC's Plan as exceeding the 3%

statutory limitation, then AIC should modify participation estimates, savings, and costs in its revised Plan such that the 3% statutory limitation is not exceeded. (Staff Group Cross Ex. 2, 15.) Staff recommended that AIC identify with specificity in its rebuttal testimony and/or compliance filing the measures it believes fall under the definition of breakthrough equipment and devices. (Staff Group Cross Ex. 2, 15.) AIC failed to identify such measures in its rebuttal testimony, and thus has failed to show that the 3% statutory limitation on breakthrough equipment and devices has not been exceeded. Accordingly, the Commission should order AIC to work with the SAG to identify measures which meet the definition recommended by Staff, and further direct that AIC shall list the measures included in its Plan which meet that criteria in a compliance filing AIC files in this docket within 45 days of the date of the Order in this docket.

V. AMEREN ILLINOIS' ENERGY EFFICIENCY AND DEMAND RESPONSE PLAN

A. Description of Ameren Illinois' Plan

1. Background

AIC filed and received Commission approval in ICC Docket No. 07-0539 ("Plan 1 Docket") of its first electric EE Plan as required under the Act which covered the period of June 1, 2008 through May 31, 2011, also referred to as electric program years ("EPY") 1 through EPY3. AIC filed and received Commission approval in ICC Docket No. 10-0568 ("Plan 2 Docket") of its first integrated gas and electric EE pursuant to Sections 8-103 and 8-104 of the Act, which covered the period of June 1, 2011 through May 31, 2014, referred to as EPY4 through EPY6 and gas program year ("GPY") 1 through GPY3. This Plan filing represents AIC's third statutorily mandated EE Plan filing and covers EPY7 through EPY9 and GPY4 through GPY6, or generally program year ("PY") 7 through PY9 covering the period June 1, 2014 through May 31, 2017. (Ameren Ex. 6.1, 2.)

2. Portfolio Summary and Objectives

3. Dual Fuel Integration

4. Planning Process

5. Savings Goals and Costs

6. Rider EDR and Rider GER

7. Portfolio Programs

(a) Residential Programs

(b) Business Programs

(c) The DCEO Portfolio

B. Filing Requirements

The minimum requirements for Commission approval of AIC's Plan are set forth in Sections 8-103(f) and 8-104(f) of the Act. These minimum requirements do not prohibit the Commission from imposing additional requirements on the utility during implementation or as part of the plan approval process. Indeed, the Commission has done so in all previous EE plan filing dockets.

DCEO's plan for implementing EE programs in the AIC service territory is the subject of a concurrent proceeding, ICC Docket No. 13-0499. Sections 8-103(e) and 8-104(e) of the Act provide that 75% of the funding shall go to the utility, while DCEO shall be allocated 25%. 220 ILCS 5/8-103(e). Therefore, 25% of the spending limits the

Commission approves in this docket will be allocated to DCEO and the funds will flow through AIC's Riders EDR and GER. DCEO's portion of the savings goals that DCEO is responsible for achieving in each utility's service territory during Plan 3 will be determined by the Commission in ICC Docket No. 13-0499.

1. Sections 8-103(f)(1) and 8-104(f)(1) of the Act

(a) Section 8-103(f)(1) of the Act

Section 8-103(f)(1) of the Act requires that "[i]n submitting proposed energy efficiency and demand-response plans and funding levels to meet the savings goals adopted by this Act the utility shall [d]emonstrate that its proposed energy efficiency and demand-response measures will achieve the requirements that are identified in subsections (b) and (c) of this Section, as modified by subsections (d) and (e)." 220 ILCS 5/8-103(f)(1). Section 8-103(b) of the Act requires electric utilities to implement cost-effective EE measures in order to achieve specific incremental annual energy savings goals: "1.8% of energy delivered in the year commencing June 1, 2014[, and] 2% of energy delivered in the year commencing June 1, 2015 and each year thereafter." 220 ILCS 5/8-103(b). In megawatt-hours ("MWh"), AIC reports that this translates into the following unmodified energy savings targets: 707,858 MWh for electric program year ("EPY") 7, 800,866 MWh for EPY8, and 805,205 MWh for EPY9. (Ameren Ex. 6.1, 4; Ameren Ex. 4.1; Ameren Ex. 1.1 (2nd Rev.), 4.)

Section 8-103(b) further provides that electric utilities may comply with "subsection (b) by meeting the annual incremental savings goal in the applicable year or by showing that the total cumulative annual savings within a 3-year planning period associated with measures implemented after May 31, 2014 was equal to the sum of each annual incremental savings requirement from May 31, 2014 through the end of the applicable year." 220 ILCS 5/8-103(b).

Section 8-103(e) specifies certain requirements for DCEO's portion of the portfolio. Among those requirements includes the provision that the utility and DCEO shall agree upon a reasonable portfolio of measures and determine the measurable corresponding percentage of savings goals associated with measures implemented by the utility or DCEO. 220 ILCS 5/8-103(e). In cases where DCEO and the utility file their respective plans with the Commission, Section 8-103(e) provides that "the Commission shall determine an appropriate division of measures and programs that meets the requirements of this Section." Id.

The Company's Plan indicates that its proposed energy efficiency measures will not achieve the unmodified energy savings requirements that are identified in Section 8-103(b) of the Act. (Staff Ex. 1.0, 14.) Accordingly, the Company has proposed modified energy savings goals. Staff's position on AIC's modified electric savings goal and spending limits were discussed above under Section IV.

Section 8-103(c) of the Act requires electric utilities to "implement cost-effective demand-response measures to reduce peak demand by 0.1% over the prior year" for certain customers. 220 ILCS 5/8-103(c). According to AIC, the Company's demand response target for Plan 3 is 1.23 megawatts ("MW") for EPY7, 1.12 MW for EPY8, and 1.07 MW for EPY9. (Ameren Ex. 6.1, 4; Ameren Ex. 4.0, 9.)

The Company's Plan demonstrates that its proposed EE and demand-response measures will achieve the required 0.1% peak demand reduction over the prior year. (Staff Ex. 1.0, 14.) No demand response program is proposed; rather, the Company proposes to meet its demand response goal for reducing peak demand through its proposed EE measures. (Ameren Ex. 1.0, 3.) Staff supports AIC's proposal. The Act defines demand response as "measures that decrease peak electricity demand or shift demand from peak to off-peak periods." 20 ILCS 3855/1-10. Allowing the implementation of EE measures that decrease peak electricity demand to count toward the statutory peak demand reduction target provides incentives to the utilities to focus on such measures. Furthermore, this is in line with the stated purpose of the statute:

> It is the policy of the State that electric utilities are required to use cost-effective energy efficiency and demand-response measures to reduce delivery load. Requiring investment in cost-effective energy efficiency and demand-response measures will reduce direct and indirect costs to consumers by decreasing environmental impacts and by avoiding or delaying the need for new generation, transmission, and distribution infrastructure. It serves the public interest to allow electric utilities to recover costs for reasonably and prudently incurred expenses for energy efficiency and demand-response measures.

220 ILCS 5/8-103(a).

(b) Section 8-104(f)(1) of the Act

Pursuant to Section 8-104(f)(1) of the Act, the Company's Plan must demonstrate that its proposed EE measures will achieve the requirements that are identified in subsection (c) of Section 8-104 of the Act, as modified by subsection (d) of that Section. 220 ILCS 5/8-104(f)(1). Section 8-104(c) of the Act requires natural gas utilities to implement cost-effective EE measures to meet at least the following natural gas savings requirements: an additional 0.8% by May 31, 2015, increasing total savings to 2.0%; an additional 1% by May 31, 2016, increasing total savings to 3.0%; and an additional 1.2% by May 31, 2017, increasing total savings to 4.2%. 220 ILCS 5/8-104(c). This calculation is based upon the total amount of gas delivered to retail customers, other than the customers described in Section 8-104(m), during calendar year 2009 multiplied by the applicable percentage. Id. After removing customers described in Section 8-104(m), AIC reports the statutory therms savings goals translate into the following: gas program year ("GPY") 4 target equal to 887,058 dekatherms (0.8% of 110,882,275); GPY5 target equal to 1,108,823 dekatherms (1.0% of 110,882,275); and GPY6 target equal to 1,330,587 dekatherms (1.2% of 110,882,275). (Ameren Ex. 9.0, 7.) Section 8-104(c) also provides that "[n]atural gas utilities may comply with this Section by meeting the annual incremental savings goal in the applicable year or by showing that total savings associated with measures implemented after May 31, 2011 were equal to the sum of each annual incremental savings requirement from May 31, 2011 through the end of the applicable year[.]" 220 ILCS 5/8-104(c).

The Company's Plan indicates that its proposed energy efficiency measures will not achieve the unmodified therms energy savings requirements that are identified in Section 8-104(c) of the Act. (Staff Ex. 1.0, 16.) Accordingly, the Company has proposed modified energy savings goals. Staff's position on AIC's modified gas savings goal and spending limits were discussed above under Section IV.

2. Sections 8-103(f)(2) and 8-104(f)(2) of the Act

The Company's Plan presents specific proposals to implement new building and appliance standards that have been placed into effect in accordance with Sections 8-103(f)(2) and 8-104(f)(2) of the Act. (Ameren Ex. 6.1, 67-68; Ameren Ex. 1.1 (2nd Rev.), 67-68; Staff Ex. 1.0, 17.)

3. Sections 8-103(f)(3) and 8-104(f)(3) of the Act

The Company's Plan presents estimates of the total amount paid for electric service expressed on a per kWh basis associated with the proposed portfolio of measures designed to meet the requirements that are identified in subsections (b) and (c) of Section 8-103, as modified by subsections (d) and (e). (Ameren Ex. 6.1, 10; Ameren Ex. 1.1 (2nd Rev.), 10; Ameren Ex. 2.0, 19-21; Ameren Ex. 4.0, 3; Staff Ex. 1.0, 17.)

The Company's Plan presents estimates of the total amount paid for gas service expressed on a per therm basis associated with the proposed portfolio of measures designed to meet the requirements that are identified in subsection (c) of Section 8-104, as modified by subsection (d) of that Section. Id.

4. Sections 8-103(f)(4) and 8-104(f)(4) of the Act

The Company is required to coordinate with the DCEO to present a portfolio of EE measures proportionate to the share of total annual utility revenues in Illinois from households at or below 150% of the poverty level and that shall be targeted to households with incomes at or below 80% of area median income. 220 ILCS 5/8-103(f)(4); 220 ILCS 5/8-104(f)(4). AIC's Plan states it has coordinated with DCEO in accordance with the Act. (Ameren Ex. 6.1, 69; Ameren Ex. 1.0, 17-18; Ameren Ex. 1.1 (2nd Rev.), 69; Staff Ex. 1.0, 18.) Staff reviewed AIC's Plan and DCEO's Plan and found this requirement to be satisfied. (Staff Ex. 1.0, 15, ICC Docket No. 13-0499.)

5. Sections 8-103(f)(5) and 8-104(f)(5) of the Act

The Company is required to demonstrate that its overall EE and demand-response portfolio, not including programs covered by item (4) of subsection (f), is cost-effective using the total resource cost ("TRC") test and represent a diverse cross-section of opportunities for customers of all rate classes to participate in the programs. 220 ILCS 5/8-103(f)(5); 220 ILCS 5/8-104(f)(5).

AIC's Plan satisfies this minimum requirement for Plan approval with a portfolio TRC benefit-cost ratio of 2.3. (Ameren Ex. 7.0, 11; Ameren Ex. 2.0, 27; Staff Ex. 1.0, 19.) Staff's discussion regarding application of the TRC test during implementation is described later in Staff's Initial Brief in Section VI.

6. Section 8-104(f)(6) of the Act

The Company is required to demonstrate that it has integrated gas and electric efficiency measures into a single program that reduces program or participant costs and appropriately allocates costs to gas and electric ratepayers. 220 ILCS 5/8-104(f)(6). Staff has reviewed the testimony of AIC witnesses Kenneth Woolcutt and Andrew Cottrell, which address integration in part. Mr. Woolcutt states that "[a]ll but two (appliance recycling and the residential lighting) programs being proposed by Ameren Illinois are designed to achieve both electric and gas savings." (Ameren Ex. 3.0, 5:70-71; *see also,* Ameren Ex. 1.0, 6:126-134; Ameren Ex. 3.0, 6-7.) The Company's Plan complies with this integrated portfolio requirement. (Staff Ex. 1.0, 22.)

7. Sections 8-103(f)(6) and 8-104(f)(7) of the Act

The Company's Plan is required to include a proposed cost-recovery tariff mechanism to fund the proposed energy efficiency and demand-response measures and to ensure the recovery of the prudently and reasonably incurred costs of Commission-approved programs. 220 ILCS 5/8-103(f)(6); 220 ILCS 5/8-104(f)(7) The Company filed exhibits containing the existing Riders EDR and GER tariff language and AIC's proposed modifications to those tariffs. (Ameren Ex. 4.3; Ameren Ex. 4.4.) Staff recommended two changes to the tariffs. Staff's discussion of its proposed tariff changes is described later in Staff's Initial Brief in Section V.C.4., "Rider EDR and Rider GER."

8. Sections 8-103(f)(7) and 8-104(f)(8) of the Act

The Company's Plan is required to provide for the following: (1) an annual independent evaluation of the performance of the cost-effectiveness of the utility's portfolio of measures and the DCEO's portfolio of measures, as well as (2) a full review of the 3-year results of the broader net program impacts and, (3) to the extent practical, for adjustment of the measures on a going-forward basis as a result of the evaluations and (4) provide that the resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given year. 220 ILCS 5/8-103(f)(7). The Company's Plan generally complies with this requirement with certain exceptions as discussed herein. (Staff Ex. 1.0, 23.) Staff's discussion regarding ensuring independence of the Evaluators and evaluations as required per the Act is described later in Staff's Initial Brief in Section VI., "Policy Issues."

Regarding 8-104(f)(8) of the Act, the Company's Plan is required to provide for the following: (1) quarterly status reports tracking implementation of and expenditures for the utility's portfolio of measures and the DCEO's portfolio of measures; (2) an annual independent review; (3) a full independent evaluation of the 3-year results of the performance and the cost-effectiveness of the utility's and Department's portfolios of measures and broader net program impacts and (4) to the extent practical, adjustment of the measures on a going forward basis as a result of the evaluations, and (5) provide that the resources dedicated to evaluation shall not exceed 3% of portfolio resources in any given 3-year period. 220 ILCS 5/8-104(f)(8).

The Company's Plan generally complies with this requirement with certain exceptions as discussed herein. (Staff Ex. 1.0, 24.) Staff's discussion regarding ensuring independence of the Evaluators and evaluations as required per the Act is described later in Staff's Initial Brief in Section VI., "Policy Issues."

Staff takes issue with the Company's assertion the Company, rather than the independent evaluator, is the appropriate party to perform the independent cost-effectiveness analysis required per Sections 8-103(f)(7) and 8-104(f)(8) of the Act. (Staff Group Cross Ex. 1, 79.) The plain language of the statute is clear that the cost-effectiveness shall be part of the independent evaluation. The Commission should specify that the independent evaluator is the appropriate party to conduct the ex post cost-effectiveness analysis required by statute and instruct AIC to specify this in its evaluation contract. The Commission should also direct that AIC require its evaluator to work with the other Illinois evaluators to ensure consistent methods and cost definitions are used to perform such ex post cost-effectiveness analyses in Illinois.

9. Sections 8-103(i) and 8-104(i) of the Act

The statute requires that if, after three years, an electric utility fails to meet the efficiency standard specified in subsection (b) as modified by subsections (d) and (e), that the electric utility will make a contribution to the Low-Income Home Energy Assistance Program ("LIHEAP"). 220 ILCS 5/8-103(i). Section 8-103(i) also requires that the responsibility for implementing EE measures shall be transferred to the Illinois Power Agency ("IPA") if, after three years or in any other three year period, the utility fails to meet the efficiency standard specified in subsection (b) as modified by subsections (d) and (e) of Section 8-103. Id.

Section 8-104(i) of the Act states:

> If, after 3 years, a gas utility fails to meet the efficiency standard specified in subsection (c) of this Section as modified by subsection (d), then it shall make a contribution to the Low-Income Home Energy Assistance Program. The total liability for failure to meet the goal shall be assessed as follows:
>
> (1) a large gas utility shall pay $600,000;
>
> (2) a medium gas utility shall pay $400,000; and
>
> (3) a small gas utility shall pay $200,000.
>
> For purposes of this Section, (i) a "large gas utility" is a gas utility that on December 31, 2008, served more than 1,500,000 gas customers in Illinois; (ii) a "medium gas utility" is a gas utility that on December 31, 2008, served fewer than 1,500,000, but more than 500,000 gas customers in Illinois; and (iii) a "small gas utility" is a gas utility that on December 31, 2008, served fewer than 500,000 and more than 100,000 gas customers in Illinois. The costs of this contribution may not be recovered from ratepayers.
>
> If a gas utility fails to meet the efficiency standard specified in subsection (c) of this Section, as modified by subsection (d) of this Section, in any 2 consecutive 3-year planning periods, then the responsibility for implementing the utility's energy efficiency measures shall be transferred to an independent program administrator selected by the Commission. Reasonable and prudent costs incurred by the independent program

> administrator to meet the efficiency standard specified in subsection (c) of this Section, as modified by subsection (d) of this Section, may be recovered from the customers of the affected gas utilities, other than customers described in subsection (m) of this Section. The utility shall provide the independent program administrator with all information and assistance necessary to perform the program administrator's duties including but not limited to customer, account, and energy usage data, and shall allow the program administrator to include inserts in customer bills. The utility may recover reasonable costs associated with any such assistance.

220 ILCS 5/8-104(i).

The Commission should direct AIC to petition the Commission for a review of whether AIC met its savings goals once the independent evaluation reports are available. (Staff Ex. 1.3, 4.)

10. Section 8-103A of the Act

Section 8-103A of the Act requires that the Company shall include in its Plan an analysis of additional cost-effective energy efficiency measures that could be implemented, by customer class. 220 ILCS 5/8-103A. Staff's discussion of the potential study submitted pursuant to Section 8-103A is described later in Staff's Initial Brief in Section VI.K., "Recommendation for Potential Study."

C. STAFF AND INTERVENOR PROPOSED CHANGES TO THE PLAN

1. Proposed Changes to Ameren Illinois' Proposed Programs

(a) Removing Programs from the Plan to the IPA Procurement Plan

(b) Cost-Ineffective Measures

(i) Furnaces and Boilers

Staff concurs in principle with the AG's proposal concerning reasons to allow AIC to pursue certain proposed non-cost-effective measures in its Plan. (AG Ex. 1.0, 47-49.) Mr. Mosenthal recommends the Commission order AIC to remove cost-ineffective boilers and furnaces from its Plan. (AG Ex. 1.0, 48-49.) Based on the additional evidence presented in Mr. Mosenthal's testimony, Staff believes that it is unreasonable to include the cost-ineffective boiler and furnace measures in the Plan. (Staff Ex. 3.0C, 22.) AIC agreed to remove these measures in rebuttal testimony.

Mr. Mosenthal makes convincing arguments with respect to: (1) furnace and boiler installations being stand-alone installations, so there are no synergies with other measures that require their inclusion in the Plan; (2) the fact that it is not sound policy to keep vendor relationships alive when there is no expectation that the efficiency measures will ever become cost-effective in the future, particularly since soon-to-be-effective federal standards provide additional justification for the measures not being expected to be cost-effective in the future and render it unlikely they could become cost-effective; and (3) the fact that including the measures reduces electric savings by limiting AIC's ability to pursue cost-effective measures in the comprehensive dual fuel EE programs with the long-life measure offerings. (AG Ex. 1.0, 49; Staff Ex. 3.0C, 22.)

Both the AG and Staff note that funds could be shifted to the cost-effective dual fuel comprehensive programs to allow more electric savings. (AG Ex. 1.0, 49; Staff Ex. 3.0C, 22-23.) Shifting budgets that are currently allocated to promoting cost-ineffective furnace and boiler measures to supplement gas budgets in the combined electric and gas programs has the beneficial effect of allowing greater efficiency to be captured. Id. As noted above, AIC's remodeled Plan filed as Ameren Ex. 6.1 excludes these measures.

(ii) Limiting Participation of Cost-Ineffective Measures

Staff's discussion concerning limiting participation of cost-ineffective measures is described later in Staff's Initial Brief in Section VI.D., "Portfolio Flexibility," and Section VI.E., "Application of Total Resource Cost Test."

(c) Multifamily Program

Mr. Grevatt recommends "that the Commission order Ameren to conduct a pilot to assess the opportunities to increase savings in the multifamily market by providing incentives through the Business programs for common area measures and common mechanical system improvements" in order "[t]o more fully capitalize on the in-person sales that Ameren is already doing[.]" (NRDC Ex. 1.0, 31.) Staff supports the conceptual outcome that Mr. Grevatt hopes to achieve, but a Commission directive to AIC to conduct a pilot as described by Mr. Grevatt is in Staff's view unnecessary. (Staff Ex. 3.0C, 32.) AIC already provides incentives for common area measures in multifamily housing units, thus a pilot program to this effect is unnecessary. (Ameren Ex. 8.0, 2-3; Staff Group Cross Ex. 1, 185; Ameren Resp. to ELPC DR 1.24 Attach 9, 49.) For example, the program year ("PY") 5 Evaluation Plan for AIC's EE portfolio states:

> The Multifamily Program encompasses three program components: Common Area Lighting, In Unit, and Major Measures … The Major Measures Component was added to the program in PY4, and experienced much higher participation than was expected, resulting in the program exceeding its electric goal by 26% and its therm goal by 271%.

(Staff Group Cross Ex. 1, 185; Ameren Resp. to ELPC DR 1.24 Attach 9, 49.) In the 2014 Procurement Plan docket, AIC has a dedicated Multifamily Program for multifamily common area electric measures. The Multifamily Program's objective in that docket is to "[d]eliver cost-effective conservation services to the multifamily housing market, with a focus on common area improvements." (Appendix B-1 to the 2014 Procurement Plan, 37, ICC Docket No. 13-0546.) The IPA is recommending Commission approval of $4,292,956 allocated to this program for PY7, the program year beginning June 1, 2014. (2014 Procurement Plan, 86, ICC Docket No. 13-0546.)

It appears that AIC, NRDC, and Staff have all reached agreement on this issue and a Commission directive to the effect initially requested by Mr. Grevatt is unnecessary. (Staff Group Cross Ex. 4, 11; Ameren Ex. 8.0, 2-3.)

(d) Using Residential Behavior Modification to Cross Promote Portfolio Incentives

(e) Other

2. Proposed New Programs

(a) Pilot C&I Program

IIEC witness Robert R. Stephens recommended that AIC should provide a proposal for a large commercial and industrial ("C&I") pilot program. (IIEC Ex. 1.0-C, 4.)

Staff does not oppose this idea in concept; however, IIEC has not provided sufficient information for Staff to fully support its proposal. There are many positive elements in ComEd's Large C&I Pilot proposal that could form the basis of something that Staff could support for AIC's service territory. (ComEd Ex. 1.0, 82-83, ICC Docket No. 13-0495.) For example, any large C&I pilot program in the AIC service territory should require projects to be cost-effective and an independent evaluation be performed on the program. (Staff Ex. 3.0C, 31.) AIC modeled an alternative scenario that includes a Large C&I Pilot. (Ameren Ex. 6.1, 124; Ameren Ex. 7.0, 5.) AIC provided almost no detail concerning the Large C&I Pilot other than the fact that its estimating a budget of $5.13 million and savings of 54,596 MWh over Plan 3. (Ameren Ex. 6.1, 124.) AIC has not provided sufficient information for Staff to support its proposal.

(b) Data Center Program

Mr. Crandall states that "[t]he Commission should direct Ameren to implement such a dedicated [data center] program or modify its existing programs and to do so in collaboration with the SAG, within six months of the issuance of the Order in this proceeding." (ELPC Ex. 1.0, 18.) AIC opposes such request as it claims it does not have a large number of data centers in its service territory. (Ameren Ex. 8.0, 6.) Rather than unconditionally "implement" a Data Center Program as requested by ELPC, Staff suggested that the Commission should direct AIC to investigate the need for, cost-effectiveness of, and feasibility of such a program. (Staff Ex. 3.0C, 30.) Such investigation should assess what the existing baseline and standard practices are for data centers operating in the AIC service territory and whether it would be cost-effective to implement a dedicated Data Center Program. (Staff Ex. 3.0C, 30.) Further, data center projects are customized projects and they already qualify under AIC's Custom Program, so a dedicated Data Center Program may not be necessary. (Staff Ex. 3.0C, 31.) To the extent the Commission orders AIC to implement a Data Center Program, the Commission should order AIC to first investigate the existing baseline and standard practices of data centers in AIC's service territory so as to reduce contention during the evaluation of such a customized program focusing on an growing market segment.

(c) Smart Devices Program

(d) Conservation Voltage Reduction Program/Voltage Optimization Program

3. Additional Financing To Customers For Energy Efficiency Measures

(a) Workshops

Mr. Crandall recommends that the "Commission instruct the Staff to conduct a workshop and the SAG to review, consider the strengths and weaknesses of the various options and prepare recommendations to the Commission regarding the use of additional financing options and alternatives including the use of amortization and capitalization of utility related costs. The recommendations should be presented to the Commission within six months of the issuance of an Order and the possibility of program changes for PY8, depending on Commission authorization and direction." (ELPC Ex. 1.0, 9.) The basis of Mr. Crandall's recommendation appears to be that "Ameren's proposed level of savings will fall short of statutory targets and additional efforts should be pursued to increase savings." (ELPC Ex. 1.0, 3.)

Both AIC and Staff urge the Commission to reject Mr. Crandall's proposal. (Ameren Ex. 8.0, 4-5.) Mr. Crandall ignores the fact that additional efforts to increase savings are already underway. (Staff Ex. 3.0C, 29.) In particular, Section 16-111.5B of the Act provides a mechanism for the Commission to approve, as part of the annual procurement plan proceedings, expansion of cost-effective Section 8-103 EE programs and new cost-effective EE programs that are incremental to the Section 8-103 EE efforts. (Staff Ex. 3.0C, 29.) Section 16-111.5B EE programs are not subject to budget constraints as the Section 8-103 EE programs are. Currently, there is an ongoing procurement plan proceeding before the Commission to consider approving Section 16-111.5B EE programs, including five for AIC's territory at a cost of $23,219,956 in PY7. (2014 Procurement Plan, 86, ICC Docket No. 13-0546.) Additionally, Sections 8-103 and 8-104 of the Act allow for modifying the statutory targets if the goals cannot be achieved within the spending limits. 220 ILCS 5/8-103(d); 220 ILCS 5/8-104(d). One key reason that the proposed level of savings will fall short of the statutory targets is due to the statutory budget restrictions. (Staff Ex. 3.0C, 30.) Given that additional efforts are already underway to increase savings based on the additional funding allowed by Section 16-111.5B of the Act and that the statutes clearly allow for modified savings goals, the Commission should decline to direct such workshops take place at this time. (Staff Ex. 3.0C, 30.)

Finally, past Commission findings support AIC's and Staff's position. In particular, ComEd's EE Plan 2 Order states:

> The Commission further finds that there is <u>no basis for requiring a utility subject to Section 8-103 to procure additional funding outside of the cost recovery mechanism authorized by Section 8-103.</u> In the Commission's

> view, Section 8-103 does not contemplate such outside funding. Rather, the statutory framework contemplates funding of the measures through the Commission-approved tariff mechanism and a reduction in measures and goals to the extent the budgets constrain the utility's ability to achieve the goals.

ICC Order Docket No. 10-0570 at 36 (Dec. 21, 2010) (emphasis added). For the aforementioned reasons, the Commission should not direct financing workshops take place. (Staff Ex. 3.0C, 30.)

(b) On-bill Financing

(c) Other Financing Proposals

4. Rider EDR and Rider GER

The Company's Plan is required to include a proposed cost-recovery tariff mechanism to fund the proposed EE and demand-response measures and to ensure the recovery of the prudently and reasonably incurred costs of Commission-approved programs. 220 ILCS 5/8-103(f)(6); 220 ILCS 5/8-104(f)(7) The Company filed exhibits containing the existing Riders EDR and GER tariff language and AIC's proposed modifications to those tariffs. (Ameren Ex. 4.3; Ameren Ex. 4.4.) Staff recommended two changes to these tariffs, as discussed below.

First, Staff recommended the removal of the requirement that evaluation reports be completed <u>before</u> the filing of testimony, because ex post evaluation reports are not needed for filing testimony in reconciliation proceedings. (Staff Ex. 1.0, 22; Staff Ex. 1.3, 25.) In rebuttal testimony, AIC agreed with Staff's recommendation. (Ameren Ex. 9.0, 3.) However, AIC's proposed language changes do not accurately reflect Staff's proposed modifications. Specifically, AIC's proposed language changes completely eliminates from the tariff the deadline for AIC to file testimony. The Commission should reject the elimination of deadlines for filing testimony as this may delay discovery and the filing of testimony and completion of the reconciliation proceedings. The Commission should also remove the requirement that evaluation reports be completed before the filing of testimony. Accordingly, the Commission should require the Company to file a revised tariff no later than 35 days after the date the Commission enters its Order in this docket which adopts the following revisions to AIC's proposed language for Riders EDR and GER:

> ~~During the annual reconciliation proceeding, t~~The Company shall file testimony by October 31~~, or 35 days after it receives the final copies of the independent evaluations. The testimony will~~ that addresses the Company's reconciliation statement and the prudence and reasonableness of costs incurred and recovered under this Rider during the Program Year that is the subject of the reconciliation statement.

AIC should file the testimony in this docket and then the Commission would initiate a reconciliation proceeding, consistent with the approach used for ComEd.

Second, the Company proposed the addition of language to Rider GER concerning the definition of Projected Costs in its rebuttal testimony. Staff agreed to the Company's proposed language change with certain additional language to remain consistent with Rider EDR. The Company indicated it did not oppose Staff's recommended modification. (Staff Group Cross Ex. 1, 135.) Accordingly, the Commission should adopt the language changes identified below and have the Company file a revised tariff in accordance with this Order no later than 35 days after the date the Commission enters its Order in this docket. In particular, the following language should be added to the definition of Projected Costs in Rider GER:

> Such Projected Costs to be recovered during the Program Year may include adjustments for (a) costs incurred related to the planning and development of plans approved by the ICC for energy efficiency programs amortized over a period of three years or other such costs related to annual reporting requirements and (b) ICC approved adjustments to Incremental Costs, if any.

5. Demand Response

(a) Introduction

Staff's discussion of the demand response goal was addressed earlier in Staff's Initial Brief in Section V.B.1.(a), "Section 8-103(f)(1) of the Act."

(b) Definition of "Eligible Retail Customers"

Ms. Devens recommends that "Ameren's demand response goal should be based on this pool of customers – i.e., all customers who are eligible to be retail customers of the utility." (CUB Ex. 1.0, 20.) The Commission should reject Ms. Devens' interpretation. (Staff Ex. 3.0C, 28; Ameren Ex. 9.0, 3-4.) The statutory definition of "eligible retail customers" clearly states that it consists of "those retail customers that purchase power and energy from the electric utility under fixed-price bundled service tariffs[.]" 220 ILCS 5/16-111.5(a). Ms. Devens' definition is inconsistent with the definition of eligible retail customers established in statute and both AIC's and ComEd's method to calculating the demand response goals. (Staff Ex. 3.0C, 28; Ameren Ex. 9.0, 3-4.)

(c) Power Smart Pricing Program

CUB recommends that Ameren investigate the cost-effectiveness of a Conservation Voltage Reduction ("CVR") Program and implement the CVR program if it is estimated to be cost-effective. (CUB Ex. 1.0, 25-28.) If the CVR program is determined to be cost-ineffective, CUB recommends that Ameren should meet its demand reduction goals by expanding its Power Smart Pricing ("PSP") Program, which CUB believes was found to be cost-beneficial to customers. Id. at 27-28.

Staff does not have an opinion on the merits of the CVR program. However, Dr. Brightwell addressed concerns with CUB's alternative that if CVR is not determined to be cost-effective that Ameren should expand the PSP Program. The PSP program is currently in effect. It is administered through Rider PSP where participating customers pay $2.25 per month and non-participating customers pay $0.08 per month Ameren Illinois Co., ICC Order Docket No. 11-0547, 3-4 (Nov. 8, 2012). It is unclear how CUB intends for Ameren to expand the PSP program through Rider EDR. PSP is now an opt-in program available to all its residential electric customers. It seems counterproductive to expand the PSP program with the limited EE funds available when Rider PSP exists and allows for cost recovery if the program is expanded.

Dr. Brightwell also indicated that the PSP program could not automatically be implemented based on the evaluation conducted to determine it was cost-effective. Section 8-103 requires cost-effectiveness based on the Total Resource Cost test. The PSP evaluation used other criteria. The PSP program would need to undergo TRC analysis before it could be expanded under Ameren's EE portfolio. (Staff Ex. 4.0, 2-4.)

Dr. Brightwell also testified that if the Commission directed Ameren to expand the PSP program under the EE portfolio it would be sacrificing energy savings in order to increase peak demand savings. This occurs because the PSP program is shown to reduce peak demand by about 0.52 kW per household, while energy savings are not statistically significant. Since the EE budget is fixed, expanding the PSP program would necessarily require expenditures on other areas of the program to be reduced and/or eliminated. Id. at 3.

It is unnecessary to expand PSP within AIC's EE portfolio, as PSP is available to all customers under a separate rider. It is also impractical. For the reasons expressed above, the Commission should reject CUB's alternative proposal to expand PSP in the event that CVR is determined to be cost-ineffective.

(d) Other

6. Miscellaneous

VI. POLICY ISSUES

Pursuant to Sections 8-103 and 8-104 of the Act, AIC is required to meet incremental energy savings targets. Failure to meet the incremental energy savings goals may result in AIC making contributions to LIHEAP and potential loss of the EE portfolio administration responsibility. 220 ILCS 5/8-103(i); 220 ILCS 5/8-104(i). Thus, AIC has an incentive to meet goals within the constraints the Commission adopts in this proceeding in order to avoid such consequences. This incentive is important to keep in mind throughout the discussion of policy issues below.

A. NET TO GROSS RATIO VALUES

A NTG ratio equals 1 – the free ridership rate + the spillover rate. If the free ridership rate is estimated as 20% and spillover is estimated as 10%, then the NTG ratio is 0.9 [(1 - 0.2 + 0.1) = 0.9]. (Staff Ex. 2.0, 4.) The value of the NTG ratio indicates what percentage of gross savings is attributable to actions of the program. In this example, it indicates that 90% of gross savings occurred as a result of program activities. Net savings is calculated by multiplying gross savings by the NTG ratio. If gross savings for a program are calculated as 1,000 kWh and the NTG ratio is calculated as 0.9, then net savings is 900 kWh (=1000 X 0.9 = 900 kWh). (Staff Ex. 2.0, 4.)

From a policy perspective, achieving gross savings is not in the best interest of ratepayers because ratepayers pay for the EE programs and ratepayers only gain benefits from net savings, not from gross savings. (Staff Ex. 2.0, 13.) Gross savings are much easier to achieve than net savings. Id. By definition, programs with high rates of free ridership have a high level of gross savings that can be achieved even without the utilities offering EE programs. Id. With a gross savings goal, a utility has an incentive to devote resources to measures and programs with high free ridership. Id. First, to the extent savings are the result of free riders, utility revenues and profits are not eroded by energy efficiency. Id. Second, it takes less effort to encourage customers to take the rebate if most of those customers were going to do the project anyway. Id. at 12-13. This is essentially the path of least resistance.

A free rider is someone who uses EE program funds to take actions that he or she would have taken anyway, even if no EE program funds were offered. The significance of a free rider is that since this customer would have installed the measure anyway, there is no incremental savings to attribute to an EE program. Sections 8-103(b) and 8-104(c) of the Act require the achievement of "incremental" energy savings goals. There are no incremental benefits associated with free riders, but there are costs associated with administration of EE programs. Id. Programs designed to cater to free riders provide little benefit, redistribute wealth (often transferring payments from less affluent individuals to more affluent individuals) and take real resources away from society through program administration. (Staff Ex. 2.0, 14-15.) The non-participating ratepayers who pay for the EE project see their money given to other ratepayers who are taking actions free riders would take without the utility intervention. Id. The EE programs are intended to encourage ratepayers to adopt EE measures which they would not adopt without the existence of the program. Using a gross savings approach undermines the intent and purpose of the EE statutes.

Spillover is more difficult to define. Dr. Obeiter provides the following definition: "Spillover includes both program participant spillover and non-participant spillover. Participant spillover is defined as additional energy efficiency actions taken by program participants as a result of a program influence that go beyond those directly incentivized or required by the program. Non-participant spillover is defined as savings from efficiency projects implemented by individuals or entities that did not participate in the program, but took actions as a result of the knowledge of the program." (Ameren Ex. 5.0, 24-25.) Dr. Brightwell describes spillover as changes in energy efficiency and conservation practices that result from increased knowledge of energy efficiency through experience with the program and/or word of mouth. (Staff Ex. 2.0, 4.) Dr. Brightwell's definition varies slightly from Dr. Obeiter's in that it does not assume that the knowledge is favorable or word-of-mouth is positive. There is the potential for customers who learned of energy efficiency having and informing others about negative experiences which dissuades them or others from taking energy efficiency actions that would have been taken if the EE program had not provided that experience or knowledge. (Staff Ex. 2.0, 4.)

1. Spillover and Free Ridership Factors for NTG Values

AIC proposes that NTG calculations include free ridership and spillover rates when both are quantified, and neither if only one or none are quantified. Ameren's proposal is intended to account for both participant and non-participant spillover. If either is excluded, then NTG ratio values exclude both free ridership and spillover. The Commission should reject such approach.

Dr. Brightwell explained that a likely consequence of approving Ameren's NTG proposal is that instead of measuring net savings, it is likely that several programs will be measuring gross savings. As Dr. Brightwell explained, it is more costly to measure spillover than it is to measure free ridership. (Staff Ex. 2.0, 5.) Due to limited evaluation funds, it is unlikely that all programs can quantify spillover, particularly non-participant spillover. Due to the difficulties associated with quantifying non-participant spillover, both free ridership and spillover rates would be excluded. The mathematical representation of net savings is (Gross Savings x NTG), where the value of NTG is equal to one minus the rate of free riders plus the rate of spillover. Id. at 4. When the rate of free riders and spillover are excluded, the NTG value is equal to one and Net Savings are equal to Gross Savings.

Dr. Brightwell provides several reasons, which will be discussed below, why AIC's proposal is not sound policy. In addition to the policy implications, Ameren's proposal is contrary to the statutory requirements of Section 8-103(b) and 8-104(c) which respectively require annual incremental savings goals to be met. Id. at 7.

Among the reasons that it is not sound policy is that the proposal is likely to overestimate savings attributable to the program and lead to incentives that are adverse to the interests of ratepayers. (Staff Ex. 2.0, 10.) Dr. Brightwell also believes that there is a disproportionate emphasis on the lack of measurement of spillover. (Staff Ex. 2.0, 7-9.)

Spillover is essentially knowledge about EE that was gained as a result of program actions. (Staff Ex. 2.0, 7.) Sections 8-103 and 8-104 of the Act set forth savings goals that relate to "incremental" first-year savings. This means that the spillover that requires measurement as far as meeting annual savings goals is indirect savings that resulted in the installation of measures in the same Program Year as the knowledge was gained. Id. That is, if a customer replaced an air conditioning unit in May of a calendar year, liked the outcome after seeing savings in the summer months, and added insulation to the house in September of the same calendar year (without using a utility rebate), then this is spillover that does not affect first year savings, as September and May are not in the same Program Year. This is also an example of participant spillover. (Staff Ex. 2.0, 7-8.) Evaluators have attempted to quantify this type of spillover and in most cases find the impact to be small and often too small to be measurable. (Staff Ex. 2.0, 8.)

For non-participant spillover to affect first year savings, the person who received the air conditioner rebate would have had to tell others, and those who received this information would have had to either have bought an air conditioner without the rebate or installed other EE devices without a rebate all within the same Program Year in which the program participant installed the air conditioner. Id. For experiences to translate to spillover that affects incremental first-year savings, a person has to be positively influenced to install some EE measure or measures and go through channels other than the utility in the process of installing the measures. Dr. Brightwell is skeptical that such events produce a large degree of nonparticipant spillover. Id.

While spillover is likely small, many programs have evaluations that have estimated free ridership of 30% or greater. Id. By not counting free ridership unless spillover is also measured, the Commission is being asked to approve a policy that would be assuming that first-year spillover is effectively 30% or more for these programs. Based on this, a gross savings approach is likely to lead to a much larger error in measuring savings than maintaining the current evaluation approach, which generally includes a free ridership factor and also includes a spillover factor where it was able to be quantified. (Staff Ex. 2.0, 8-9.)

Of course, there other means by which spillover may occur. By marketing the ActOnEnergy program, it is possible that Ameren is creating greater general awareness of EE which cause EE investments to occur outside of program channels. (Staff Ex. 2.0, 9.) However, marketing does not provide a sufficient spillover impact to offset the reduction in gross savings that are attributable to free ridership. Id. It needs to be pointed out that marketing that is effective at getting ratepayers to use utility programs is not spillover. Id. Spillover only occurs when marketing is effective at enticing ratepayers to install EE measures without a utility rebate or program. Id. The idea of customers performing EE investments as a result of learning about EE investments from the program's marketing efforts prompts the question of why a customer who is aware of and eligible for a rebate would not use the program to receive a rebate. Id. This tends to further suggest that it is unlikely that first-year spillover is causing substantial measurement error in net savings. Id.

Dr. Obeiter contends that customers do in fact purchase equipment as a result of the rebate but then not apply for the rebate. He uses himself as an example. (Ameren Ex. 10.0, 15.) However, Dr. Obeiter's example begs the question of why an expert in energy efficiency would require an incentive to install a particular measure. It is more likely that Dr. Obeiter is not an example of spillover but rather an example of an unrealized free rider (i.e., he would have known about the cost effectiveness of the measure, and put it in without a rebate, so if he had taken the rebate, he would have been a free rider, not an example of spillover).

Another potential means through which spillover may occur is through non-participating trade allies promoting EE equipment. (Staff Ex. 2.0, 10.) However, this is a gray area that can cause an over-calculation of first-year savings and lead to unnecessarily prolonging the continuation of programs. (Staff Ex. 2.0, 10.) A trade ally is a contractor or vendor who registers with the EE program, receives information about the rebate process, some training on promoting EE equipment, and potentially some training on differences in the installation of EE equipment versus standard energy-using equipment. <u>Id.</u>

The theory is that these non-participating trade allies use the information provided by the program to promote the sale of EE equipment but do not actively participate in the program. <u>Id.</u> The concept is that EE investments would be made because of the program without the programs receiving credit.

However, since any savings from nonparticipating trade allies is by definition savings that results from the EE program having "past" involvement with the non-participating trade allies, it seems that savings attributable to these contractors can either be categorized as inter-temporal spillover, spillover that occurs in the present from past actions, or perhaps as market transformation. Id. In the event that it is inter-temporal spillover, there is negligible incremental first-year savings attributable to the program. Id. If non-participating trade ally activity is better classified as market transformation, then once these contractors receive the information, they are actively using the knowledge gained to promote EE equipment indefinitely. (Staff Ex. 2.0, 10.) Staff does not believe that market transformation or inter-temporal spillover meet the legal requirements of incremental annual energy savings specified in Sections 8-103(b) and 8-104(c) of the Act.

Additionally, there are biases that work in the favor of the utilities in determining Net Savings. (Staff Ex. 2.0, 11.) The measure of energy savings compares the difference in energy use between an energy efficient device and another device that serves as a baseline. Id. The baseline device is simply assumed to be in many cases the minimally efficient device permitted by an appliance standard. Id. If one was accurately measuring energy savings the baseline device would be the device a customer would have installed if the more efficient device was not installed. Id. If a ratepayer would have installed the minimally efficient device without the existence of the EE program, the baseline is correct. If the ratepayer would have installed a device that was more efficient than the assumed baseline but less efficient than the device for which an incentive is received, the baseline is incorrect and gross savings are overestimated. Id.

Two examples where this phenomenon is likely happening are furnaces and lighting. (Staff Ex. 2.0, 11.) The current baseline for furnaces is an 80% Annual Fuel

Utilization Efficiency ("AFUE") furnace. Id. A 90% AFUE furnace standard was expected to become effective in 2013. (Staff Ex. 2.0, 11-12.) The 90% AFUE furnace standard was suspended indefinitely to receive further comment and to do more analysis. Id. Staff understands that part of the motivation to increase the standard to 90% was a belief that the 80% standard was lower than the efficiency level most customers were choosing for replacements of old furnaces or for furnaces in new facilities. (Staff Ex. 2.0, 12.) To the extent customers are choosing furnaces between 80% and 90%, the baseline for furnaces overestimates the actual incremental savings. Id.

Residential lighting standards began changing in January 2012 when requirements from the Energy Independence and Security Act of 2007 ("EISA") started becoming effective. (Staff Ex. 2.0, 12.) In January 2012, EISA required lumen outputs that were previously achieved with 100 Watt incandescent bulbs to be achieved with 72 Watts or fewer. Id. This changed the assumed baseline from 100 Watts to 72 Watts. The incremental savings from lighting is now the difference between an efficient bulb of equivalent lumens and a 72 Watt bulb. Id. This very well may be an incorrect baseline as lighting manufacturers are not producing 72 Watt incandescent bulbs with prices close to the 100 Watt incandescent bulbs. Id. Instead, 72 Watt bulbs tend to be halogen lights that cost as much or more than CFLs. It could be argued that CFLs should be the baseline. Id. If a CFL is in fact the correct baseline, every CFL sold generates no incremental savings. However, under the currently assumed baseline, positive gross savings are assumed. Id. Further, if a customer installs a light more efficient than a CFL rather than a CFL, it is assumed that a 72 Watt bulb is the baseline.

For all customers who would have purchased the CFL rather than the baseline light, gross savings are overstated.

AIC's proposal to only include free rider estimates when spillover is also estimated fails to consider that net savings is the product of multiplying gross savings by the NTG ratio. (Staff Ex. 2.0, 13.) If gross savings are overestimated and a NTG ratio that excludes spillover is underestimated, it cannot be concluded that net savings are underestimated. Id. Ameren's proposal presumes that the inherent bias works against the Company and is of such magnitude that a better alternative is to ignore any estimate of free ridership when it is too costly or difficult to estimate spillover. Id.

From a policy perspective, achieving gross savings is not in the best interest of ratepayers because ratepayers pay for the EE programs. (Staff Ex. 2.0, 13.) Ratepayers only gain benefits from net savings, not from gross savings. Gross savings are much easier to achieve than net savings. Id. By definition, programs with high rates of free ridership have a high level of savings that can be achieved even without any utility intervention. Id. With a gross savings goal, a utility has an incentive to devote resources to these types of programs. Id. First, to the extent savings are the result of free riders, utility revenues and profits are not eroded by energy efficiency. Id. Second, it takes less effort to encourage customers to take the rebate if most of those customers were going to do the project anyway. (Staff Ex. 2.0, 12-13.) This is essentially the path of least resistance.

Unfortunately, free ridership provides little or no benefit to ratepayers as a group. (Staff Ex. 2.0, 14.) Funding programs or measures for which the market has been transformed by any cause including past utility actions into a marketplace now making

EE investment the norm results in reduced funding for programs and measures that provide incremental energy savings that are required to reduce direct and indirect costs to ratepayers, and satisfy the underlying purpose of the statutory targets. The EE programs are intended to encourage ratepayers to adopt EE measures which they would not adopt without the existence of the program. Using a gross savings approach, which may occur if AIC's recommendation to exclude free-ridership when spillover cannot be quantified is adopted, undermines the intent and purpose of the EE statutes.

The Commission has previously commented on "spillover" in AIC's Plan 1 Order. The Plan 1 Order states:

> However, we decline to order Ameren to exclude "spillover" from any Net to Gross ratio calculation. While the NRDC avers, essentially, that this would save money, no evidence regarding this issue was presented at trial. It is therefore waived. Moreover, because there is no evidence on this issue, there is no showing that excluding "spillover" would not skew the ratios, how much money would be saved, or other facts that would establish that such a proposition would be a prudent course of action. Finally, Mr. Jensen testified, essentially, that calculation of "spillover" is the accepted practice in the evaluation community. There is no evidence suggesting that this is incorrect.

ICC Order Docket No. 07-0539 at 33 (Feb. 6, 2008).

Further, AIC has been unable to adequately support the basis of its recommendation. (Staff Group Cross Ex. 1, 73-74.) In particular, while AIC makes the recommendation that non-participant spillover and participant spillover must be included in every single deemed NTG ratio value, AIC is unable to explain how both components of spillover could occur for each program when requested. (Staff Group Cross Ex. 1, 73-74.) It is likely the case that it may not make sense for certain programs to have a specific kind of spillover, and if that is the case, under AIC's recommendation the evaluators would be required to develop a value for this where there is no theoretical basis for such value.

Since AIC has been unable to support how spillover could occur for each of the programs, the Commission should not require both components of spillover be included in the NTG value for each program. The Company has not provided support for their position. Staff asked AIC for support for its recommendation. (Staff Group Cross Ex. 1, 73-74.) AIC responded that the question was in the purview of the evaluator, who essentially works under AIC's direction/control. (Staff Group Cross Ex. 1, 73-74.) It is reasonable to infer that if the evaluator's response would be supportive of AIC's position, AIC would have provided it. *See, e.g.*, Shumak v. Shumak, 30 Ill. App. 3d 188; 332 N.E.2d 177 (2nd Dist. 1975) (where a particular necessary fact rests peculiarly within the knowledge of one of the parties it is his duty to come forward with the proof and if he fails to do so, an inference or presumption is raised that the evidence, if produced, would be unfavorable to his cause). The fact that AIC gave a non-answer leads Staff to believe that the answer from the evaluator would not be supportive of AIC's position.

For the reasons provided above, the Commission should reject AIC's proposal. The Commission should instead instruct the independent evaluators to make reasonable efforts to calculate both free ridership rates and spillover rates while being mindful of: (1) the costs of such evaluations, (2) the likely magnitudes of spillover and free ridership rates within a program, and (3) the significance of the program to the overall portfolio savings. If the Commission adopts AIC's proposal, Staff would urge the

Commission to require consistent NTG methodologies for measuring free ridership and spillover as discussed later in this Initial Brief.

2. Modified NTG Framework Proposals

(a) Background

In the 2010 EE Dockets, the Commission approved a NTG framework for the utilities. (Staff Ex. 1.0, 31-32.) Among the reasons parties proposed the NTG Framework was that there is a lag between the time evaluations are completed and the end of a program year. (Staff Ex. 2.0, 16.) The result of the lag is that a utility will not know whether a program was effective at meeting savings goals until six months or more into the next Program Year. Id. The NTG framework proposed in the 2010 dockets was intended to provide greater certainty to a utility by apply a prospective NTG ratio in most circumstances. Id. Under the Plans approved in the 2007 EE Plan filings, NTG ratios were applied retrospectively. Id. In the 2010 Plans, the circumstances that were intended to warrant a retrospective NTG ratio application were if a program was new and no previous evaluation had been conducted or if the program had undergone significant change as a result of market changes or program delivery methods. (Staff Ex. 2.0, 17.)

The framework was difficult to manage because it was unclear what constitutes a significant change. (Staff Ex. 2.0, 17.) In the current Plan filing, Ameren proposed to apply planning assumption NTG values to any new programs and to apply prospective NTG values to all other programs. (Ameren Ex. 1.0, 11.) Staff offered an alternative that is provided as Staff Ex. 3.1. Staff's proposed NTG framework includes dates by which various tasks need to be completed in order to allow the utilities to reach the March 1 planning deadline that Mr. Goerss requested in his direct testimony. (Staff Ex. 1.0, 33; Ameren Ex. 1.0, 11.) The AG and ELPC also offered NTG Frameworks similar to that proposed by Staff. (AG Ex. 1.1; ELPC Ex. 1.4.) AIC provided a counter proposal in its rebuttal testimony wherein it prefers Staff's Modified Illinois NTG Framework presented in Staff Ex. 3.0 with five proposed changes over the AG/ELPC NTG Framework. (Ameren Ex. 6.0, 8-10.)

(b) Overview of Staff's Modified Illinois NTG Framework

As noted above, the original NTG framework was difficult to manage because it was unclear what constitutes a significant market change. (Staff Ex. 2.0, 17.) To address significant market change, Staff's NTG Framework proposal has two components. (Staff Ex. 2.0, 17.) First, it removes the ambiguous phrase "significant" market change. Id. Instead of a "significant" market change triggering a retrospective evaluation, there will be a partially retrospective application at times when the parties cannot reach consensus on a prospective NTG value. Id. The second part is changing the retrospective application that occurs under the previously approved NTG Framework to a potentially partial retrospective application. Id.

Since evaluation reports are not completed until about November of the following program year, there is a two-year lag between the time the NTG values go into effect for prospective application. (Staff Ex. 2.0, 18.) That is, the PY1 evaluations were not complete until midway through PY2 and would not apply for prospective application until PY3. Id. As a result, prospective application estimates savings based on conditions that are about two years old at the time the NTG ratio values are being applied. Id.

When the market is stable, this may be a reasonable approach. Id. When the market is changing, a NTG ratio value that is two years out of date by the time it is applied is problematic because it requires utility ratepayers to bear all of the risks in times of uncertain market conditions. Id.

One area of disagreement about whether there is significant market change is in the residential lighting market. (Staff Ex. 2.0, 18.) There are disputes about whether the EISA provisions eliminating the manufacture of certain incandescent light bulbs along with a general acceptance of compact fluorescent lamps ("CFLs") by consumers created a significant market change. Id. The evaluated NTG ratio for PY5 is 0.44 while using a prospective NTG ratio from PY2 results in a NTG ratio of 0.83 being applied. Id. By using the 0.83 NTG ratio value from PY2, AIC is essentially claiming 47% greater "paper savings" from residential lighting than actually occurred during PY5 according to evaluations. (Staff Ex. 2.0, 18-19.) This is beneficial to AIC but its ratepayers may be better off if some of this money was spent elsewhere. (Staff Ex. 2.0, 19.)

Under Staff's proposal, in times when a consensus cannot be reached, that the NTG ratio ("NTGR") applied in PYt+1 would be the average of evaluated NTGRs conducted in PYt-1 and PYt. (Staff Ex. 2.0, 19.) For example, if parties cannot reach a consensus on a NTG ratio value for the upcoming PY7 that begins on June 1, 2014, then the average of the evaluations for the PY5 and PY6 evaluations would be applied. Id.

Staff's proposal provides more certainty than the current approach of a fully retrospective NTG application for programs undergoing significant market change because the evaluation result from PYt-1 should be known at the time that planning for

PYt+1 takes place. (Staff Ex. 2.0, 19.) In some cases, the estimated NTG ratio for PYt may be available by March 1 of the current program year as well. Id. However, it still provides some uncertainty and risk because the result of PYt is not known by the time that the utility has to make plans for PYt+1. Id.

Since there is a degree of uncertainty, the utility has an incentive to agree to a consensus deemed value reflective of the value likely to exist in the program year or to move funds away from a risky proposition and towards less risky propositions. (Staff Ex. 2.0, 19.) This provides benefits to ratepayers because the utility now has an incentive to manage risky programs rather than to divert the risk to ratepayers. (Staff Ex. 2.0, 19-20.)

The independent Evaluators have expertise about all aspects of NTG values and familiarity with AIC's programs, thus having initial recommendations come from the independent EMV Evaluators is efficient and appropriate as outlined in Staff's and the AG/ELPC NTG Frameworks. In order to help ensure the independence of the Evaluators is not being compromised by pressure from the utility who desires to have high NTG values and who holds the contract with the Evaluators, it is necessary to take the decision concerning the final deemed NTG values away from the Evaluators. Further, there is value in the Evaluators estimating NTG values because these estimated values can help inform future deemed NTG values. It also provides parties with information concerning the impact of the EE program and can further help inform program design modifications. (Staff Group Cross Ex. 2, 28.) The Commission should adopt the Modified Illinois Net-To-Gross Framework set forth below.

(i) Modified Illinois Net-To-Gross Framework (Staff Ex. 3.1.)

In order to provide the proper incentives to encourage a Utility to make appropriate program changes to ensure against high free-ridership in the following program year (PYt+1),[1] the basis of deeming[2] a specific net-to-gross ratio ("NTGR") value shall be that it represents the best estimate of what the evaluated NTGR value would reasonably be expected to be in the following program year (PYt+1) taking into consideration the best information available about the measure, program design, incentive levels, market, energy codes, and any other factors that could influence the level of free-ridership and spillover in the following program year (PYt+1). The following eleven steps set forth the Modified Illinois Net-To-Gross Framework.

(1) Each Evaluator shall submit to the Utility, ICC Staff, Illinois Energy Efficiency Stakeholder Advisory Group ("SAG") Facilitator, and/or the SAG a memorandum documenting the NTGR values, showing both free-ridership and spillover components, that it proposes to deem for the following program year (PYt+1) (hereinafter, "*Evaluator's Memo on Proposed NTGRs for PYt+1*"). The basis of the Evaluator's proposed NTGR values shall be its best estimate of what the evaluated NTGR would reasonably be expected to be in the following program year (PYt+1) based on the best information available about factors that could influence the level of free-ridership and spillover in the following program year (PYt+1).

a. Each *Evaluator's Memo on Proposed NTGRs for PYt+1* shall include the following information:

i. the scope of what each proposed NTGR value would be applicable to (e.g., specific measure technology, IL-TRM measure name and code, measure type, program element, program, fuel type savings);

[1] The nomenclature used in this document uses "t" to denote a time variable. PYt represents the current program year, PYt+1 reflects the next program year, and so on.
[2] Deeming of a NTGR value means that the Utility knows with certainty that the deemed NTGR value will ultimately be applied by the Commission in evaluating whether the Utility complied with the statutory savings goals set forth in Sections 8-103 and 8-104 of the Illinois Public Utilities Act ("Act").

ii. the previously evaluated NTGR values (including draft evaluation results when final evaluation results are not available), showing both free-ridership and spillover components, along with NTGR methodology type, sample size, references, and other relevant information;

iii. the Evaluator's proposed NTGR values showing both free-ridership and spillover components; or if retroactive[3] application is preferred for the free-ridership and/or spillover components, then the proposed evaluation approach for estimating the NTGR component for PYt+1;

iv. the rationale for why the proposed NTGR value is the best estimate of what the evaluated NTGR would reasonably be expected to be in the following program year (PYt+1) after taking into consideration the best information available to the Evaluator from primary or secondary evaluation research about the measure, program design, incentive levels, market, energy codes, and any other factors that could influence the level of free-ridership and spillover in the following program year (PYt+1);

v. if evaluations from other jurisdictions are relied upon, relevance to the Illinois energy efficiency program in question shall be demonstrated and the NTGR methodology type, sample size, references, and other relevant information shall be provided;

vi. a table identifying the NTGR values proposed for deeming for PYt+1.

(2) Utilities host a teleconference meeting for SAG participants to discuss *Evaluator's Memo on Proposed NTGRs for PYt+1* (allows for questions from all parties, clarifications, discussion of rationale, raise concerns, etc.).

(3) All non-evaluator parties (jointly or individually) can submit *Party's Memo on Proposed NTGRs for PYt+1 – Response to Evaluator.*

(4) Utilities host a teleconference meeting for SAG participants to discuss NTGR values and *Party's Memo(s) on Proposed NTGRs for PYt+1 – Response to Evaluator* and attempt to reach consensus. Evaluators distribute detailed meeting notes no later than three days after the meeting.

(5) Evaluator's Revised Memo on Proposed NTGRs for PYt+1 incorporating consensus items and their proposed resolution for any non-consensus items.

[3] Retroactive application means that the Utility does not know with certainty the NTGR value that will ultimately be applied by the Commission in evaluating whether the Utility complied with the statutory savings goals. This uncertainty will persist until the Commission makes a decision in the Utility's compliance with energy savings goal docket.

(6) All non-evaluator parties (jointly or individually) may submit *Party's NTGR Objection Memo* clarifying any remaining non-consensus positions, if any. A *Party's NTGR Objection Memo* shall be submitted to the Utility, SAG Facilitator, ICC Staff, and/or the SAG that documents any objections to the proposed NTGR values contained in the *Evaluator's Revised Memo on Proposed NTGRs for PYt+1*. Failure of a party to submit a *Party's NTGR Objection Memo* by the deadline specified shall be construed as concurrence with deeming the NTGR values proposed in the *Evaluator's Revised Memo on Proposed NTGRs for PYt+1*. If no *Party's NTGR Objection Memo* is submitted on a particular proposed NTGR value by the deadline specified, then the Evaluator's proposed NTGR value contained in the *Evaluator's Revised Memo on Proposed NTGRs for PYt+1* is considered to be "consensus"[4] and shall be effectively deemed for the next program year (PYt+1).

(7) Utilities host a teleconference meeting(s) for SAG participants to discuss the *Evaluator's Revised Memo on Proposed NTGRs for PYt+1* and any *Party's NTGR Objection Memo(*s), and attempt to reach consensus. Evaluators distribute detailed meeting notes no later than three days after the meeting(s).

(8) <u>In cases where consensus is not reached</u> on an individual NTGR value by February 20 (i.e., a *Party's NTGR Objection Memo* is received regarding an individual NTGR value and is not resolved by February 20), the non-consensus individual NTGR value for the applicable program year (PYt+1) shall be deemed at the average of the evaluated NTGR values[5] from PYt and PYt-1.[6] In the event there is non-consensus on an individual NTGR value and there are no Illinois evaluations available, an explanation of the non-consensus issue may be filed with the Commission with a request for resolution prior to June 1.

(9) Evaluator's Memo on Deemed NTGRs for PYt+1 should reflect the final consensus NTGR values and non-consensus deemed NTGR formulas with NTGR values where available that are applicable to PYt+1.

(10) Utilities shall file in the initial TRM approval docket 12-0528 a list of the consensus NTGR values and non-consensus deemed NTGR formulas with NTGR values where available that are applicable to PYt+1 and supporting work papers (i.e., *Evaluator's Memo on Proposed NTGRs for PYt+1, Party's Memo(s) on Proposed NTGRs for PYt+1 – Response to Evaluator, Evaluator's Revised Memo on*

[4] Consensus means that no party indicates they oppose a specific NTGR value enough to contest it before the Commission.
[5] Evaluated NTGR values are NTGR values estimated by the evaluators using only data collected from the Utility's customers and contractors in the Utility's service territory.
[6] If only one evaluated NTGR value will be available, then that single evaluated NTGR value shall be deemed.

Proposed NTGRs for PYt+1, Evaluator's Memo on Deemed NTGRs for PYt+1). Supporting work papers help ensure compliance with the NTG Framework process. In the event that consensus is not reached on a new program NTGR value, then the respective Utility may file a petition requesting the Commission establish a deemed NTGR value. The filing will articulate the Evaluator's and the Utility's positions and rationale for deeming specific NTGR values. Failure of a Utility to file consensus and non-consensus deemed NTGR values with supporting work papers by March 5 (PYt) results in retroactive application[7] of NTGR values for that upcoming program year (PYt+1).

(11) While deemed NTGR values are not subject to retroactive adjustments based on new evaluation findings, the evaluation reports will show both deemed savings (based on deemed NTGRs for purposes of crediting Utility savings) as well the actual estimated NTGR value and net savings for that program year. While the deemed values will be the official claimed savings, and filed by each Utility in its respective compliance with energy savings goal docket, the information will provide straightforward and transparent data on the Evaluators' best estimates of net savings, as well as a comparison of how close the deemed NTGR values are to the final evaluation results.

Finally, Table 1 outlines the deadlines associated with the Modified Illinois Net-To-Gross Framework.

[7] Retroactive application means that the Utility does not know with certainty the NTGR value that will ultimately be applied by the Commission in evaluating whether the Utility complied with the statutory savings goals. This uncertainty will persist until the Commission makes a decision in the Utility's compliance with energy savings goal docket.

Table 1. Modified Illinois Net-To-Gross Framework Timeline		
	Residential Programs	**Non-Residential Programs**
	On or before…	**On or before…**
(1) *Evaluator's Memo on Proposed NTGRs for PYt+1*	November 1	December 1
(2) Utilities host a teleconference meeting for SAG participants to discuss *Evaluator's Memo on Proposed NTGRs for PYt+1* (allows for questions from all parties, clarifications, discussion of rationale, raise concerns, etc.)	November 15	December 10
(3) All non-evaluator parties (jointly or individually) can submit *Party's Memo on Proposed NTGRs for PYt+1 – Response to Evaluator*	December 1	December 20
(4) Utilities host a teleconference meeting for SAG participants to discuss NTGR values and *Party's Memo(s) on Proposed NTGRs for PYt+1 – Response to Evaluator* and attempt to reach consensus. Evaluators distribute detailed meeting notes no later than three days after the meeting.	December 10	January 15
(5) *Evaluator's Revised Memo on Proposed NTGRs for PYt+1*, incorporating consensus items and their proposed resolution for any non-consensus items.	December 20	January 25
(6) All non-evaluator parties (jointly or individually) may submit *Party's NTGR Objection Memo* clarifying any remaining non-consensus positions, if any.	January 10	February 5
(7) Utilities host a teleconference meeting(s) for SAG participants to discuss the *Evaluator's Revised Memo on Proposed NTGRs for PYt+1* and any *Party's NTGR Objection Memo(s)*, and attempt to reach consensus. Evaluators distribute detailed meeting notes no later than three days after the meeting(s).	February 20	February 20
(8) In cases where consensus is not reached on an individual NTGR value by February 20 (i.e., a *Party's NTGR Objection Memo* is received regarding an individual NTGR value and is not resolved by February 20), the non-consensus individual NTGR value for the applicable program year (PYt+1) shall be deemed at the average of the evaluated NTGR values from PYt and PYt-1. In the event there is non-consensus on an individual NTGR value and there are no Illinois evaluations available, an explanation of the non-consensus issue may be filed with the Commission with a request for resolution prior to June 1.	February 20	February 20
(9) *Evaluator's Memo on Deemed NTGRs for PYt+1*	February 25	February 25
(10) Utilities shall file in the initial TRM approval docket 12-0528 a list of the consensus NTGR values and non-consensus deemed NTGR formulas with NTGR values where available that are applicable to PYt+1 and supporting work papers (e.g., *Evaluator's Memo on Deemed NTGRs for PYt+1*). In the event that consensus is not reached on a new program NTGR value, then the respective Utility may file a petition requesting the Commission establish a deemed NTGR value. The filing will articulate the Evaluator's and the Utility's positions and rationale for deeming specific NTGR values. Failure of a Utility to file consensus and non-consensus deemed NTGR values with supporting work papers by March 5 (PYt) results in retroactive application of NTGR values for the upcoming program year (PYt+1).	March 5	March 5
Note: All memorandums shall be submitted to the Utility, SAG Facilitator, ICC Staff, and/or the SAG.		

(c) AIC's Changes to Staff's Modified NTG Framework

AIC recommends five modifications to Staff's Modified Illinois NTG Framework. (Ameren Ex. 6.0, 8-10.)

(1) The Company first proposes that the Commission should limit participation of those SAG members who have a conflict of interest, because the work of the SAG, including setting NTG values, should be done free from such conflicts of interests. (Ameren Ex. 6.0, 8.) AIC provides no explanation of how the Commission would be able to limit participation in the SAG considering the Commission established the SAG as a group open to all interested parties. Presumably the Commission would need to specifically identify and rule on which SAG members have a conflict of interest, which would necessitate a separate proceeding, and potentially multiple proceedings as the participants in the SAG have changed over time. Such a process would have a chilling effect on SAG participation and the breadth of views provided by SAG to the Commission. Accordingly, AIC's recommendation in this regard is unspecified and unworkable and should be rejected by the Commission.

(2) AIC proposes changing how non-consensus NTGR values are addressed. In particular, AIC proposes changing "evaluated NTGR" to the phrase "average of the SAG participants' proposed NTGR values for PYt+1." (Ameren Ex. 6.0, 9.)

> In cases where consensus is not reached on an individual NTGR value by February 20 (i.e., a Party's NTGR Objection Memo is received regarding an individual NTGR value and is not resolved by February 20), the non-consensus individual NTGR value for the applicable program year (PYt+1) shall be deemed at the average of the SAG participants' proposed NTGR values for PYt+1.

(Ameren Ex. 6.0, 9.) AIC's proposal is problematic for two reasons. First, it allows parties to affect the average by enabling them to propose arbitrarily large or small

NTGR values. Second, the definition for what constitutes a SAG participant by arbitrarily allowing a party to deem themselves as separate participants could unduly influence the level of such average. For example, a trade association of 500 members, could have each member designate itself as a separate vote, and substantially influence the average NTGR that would be deemed. Further, AIC's proposal provides an incentive for utilities to propose high NTGR values, which undermines the stated purpose of the framework. The deemed NTGR values should reflect the best estimates of what the actual NTGRs would be. If the Commission adopts AIC's modification, which it should not, then the Commission should limit the range that proposed NTGR values can take. The Commission should order the proposed NTGRs cannot take values less than zero and greater than one.

(3) AIC proposes establishing that non-consensus NTGR values for "unanticipated" new programs will be established by taking an average of all SAG participant recommended NTGR values.

> For new unanticipated programs implemented during the program year after June 1, the utility's evaluator will provide a recommended NTGR value for that program to be deemed for that first year of implementation. The evaluator will provide the recommended value in writing with appropriate justification. The utility will provide the evaluator's NTGR value to the SAG membership and request a recommended NTGR value for the new program from SAG participants. The average of all SAG participant recommended NTGR values will be the deemed value for that new program for that year (PYt). The utility will file that deemed value in the applicable Plan approval docket within 60 days accompanied by verification of the SAG and evaluator's values. Otherwise, the utility is subject to a retroactive application of the program's NTGR value as determined per this framework.

(Ameren Ex. 6.0, 9.) In response, Staff submits that AIC's proposal provides an incentive to bias participants' proposed NTGR values and because of the unspecified determination of exactly what constitutes a "SAG participant," the average can be biased by representing each member of a group as a separate voting entity. It is not clear whether all environmental organizations would constitute one SAG participant, or whether each individual participating in the SAG would be considered a "SAG participant" for voting purposes. It is fundamentally flawed because it provides voting and weights on those votes as discussed in response to the second item. AIC's proposed addition of a process for deeming NTGR values for "unanticipated" new programs may be due to the programs approved by the Commission under Section 16-111.5B of the Act, since the Commission would approve such programs in December of a program year, after the date Staff's Modified Illinois NTG Framework timeline starts. Staff believes AIC can request the Commission to deem specific NTGR values for these unanticipated Section 16-111.5B EE programs in the procurement plan proceeding, which is consistent with the approach AIC took this year in ICC Docket No. 13-0546, and thus no modifications to Staff's NTG Framework are warranted in this regard. For "unanticipated" new programs not covered by Section 16-111.5B, these could be implemented as an experimental program.

Additionally, the Company would have flexibility to size the unanticipated new program to limit its exposure to NTG risk. In other words, the Company does not face unmanageable NTG risk for unanticipated new programs considering the small size of the program relative to the entire portfolio. AIC was able to effectively manage the risk without any deeming of NTGRs during Plan 1 and still able to achieve its savings goals. Now AIC is asking for the relief of minimal risk associated with a likely small unanticipated new program. Staff believes the Company is finding problems where none exist.

(4) AIC proposes to change the filing location of NTG values to be in this docket as opposed to ICC Docket No. 12-0528. (Ameren Ex. 6.0, 10.) Staff's initial NTG proposal endorsed the location as recommended by AIC; however, based on input from stakeholders, Staff modified the location to be a docket with all program administrators.

(5) The Commission should allow the SAG to modify any NTG Framework, without Commission approval, through the consensus process. (Ameren Ex. 6.0, 10.) This recommendation ignores the Commission's stated concerns regarding granting stakeholders decision-making authority, as it gives rise to the possibility of conflicts of interest, among other issues. Accordingly, this recommendation should be rejected.

(d) AG/ELPC NTG Framework

AG witness Mosenthal and ELPC witness Crandall recommend adoption of the Proposed Modified Illinois NTG Framework (AG Ex. 1.1; ELPC Ex. 1.4) ("AG/ELPC NTG Framework") that they each have attached to their direct testimony. (AG Ex. 1.1; ELPC Ex. 1.4.) Mr. Mosenthal states that "it is important that any NTG procedures be consistent and applied equally to all program administrators." (AG Ex. 1.0, 37.) Staff agrees with Mr. Mosenthal and notes that this position is consistent with the Commission's adoption of the original NTG Framework procedure across all the utilities' dockets in the last three-year Plan filings. (ICC Orders Docket Nos. 10-0562, 10-0564, 10-0568, 10-0570.) It should also be noted that Staff's Modified Illinois NTG Framework (Staff Ex. 3.1) has been filed in the other program administrators' plan filing dockets such that the Commission could adopt a consistent Modified Illinois NTG Framework across all program administrators. (Staff Ex. 3.1; Staff Ex. 1.1, ICC Docket No. 13-0495; Staff Ex. 3.1, ICC Docket No. 13-0499.) While the AG/ELPC NTG Framework and Staff's Modified Illinois NTG Framework are substantially similar, they are not identical, and two of the differing components proposed by Staff have been supported by the AG: (1) timeline for NTG updates and (2) resolution for non-consensus NTG updates. (AG Ex. 2.0C, 3-4.) The AG acknowledges that Staff's proposal "will result in, all else equal, likely better estimates of actual future NTG ratios" and "it provides a reasonable but significant incentive for all parties to reach consensus on a best estimate of future NTG ratios[.]" (AG Ex. 2.0C, 5.) For the reasons described herein, the Commission should adopt Staff's Modified Illinois NTG Framework proposal. While Staff supports a number of elements contained in the AG/ELPC NTG Framework as it is substantially similar to Staff's proposal, there is one element in particular that Staff simply cannot support: the creation of "voting parties." (Staff Ex. 3.0C, 13; AG Ex. 1.1, 2; ELPC Ex. 1.4, 2.) The creation of "voting parties" is the third substantive difference between the frameworks that Mr. Mosenthal describes in his testimony. (AG Ex. 2.0C, 6.) Please note that there are more than three differences between the AG/ELPC NTG Framework and Staff's Modified Illinois NTG Framework, though not all are addressed here. For example, the AG/ELPC NTG Framework "requires" the utilities to petition the Commission to rule on deeming a NTGR value that is non-consensus in the event there are no Illinois evaluations available for the program (AG Ex. 1.1, 2; ELPC Ex. 1.4, 2), whereas Staff's Modified Illinois NTG Framework provides utilities with the "option" to petition the Commission in this situation (Staff Ex. 3.1, 3, 5).

Finally, within the AG/ELPC NTG Framework, there are some internal inconsistencies and other elements that would be unworkable in practice (e.g., deadlines for filing in the IL-TRM annual update docket, missing definition of evaluated

NTGR values) should the Commission decide to approve the AG/ELPC NTG Framework without modification. (Staff Ex. 3.0C, 13.) Each of these issues are addressed in turn below.

(i) Creation of Voting Parties is Contrary to Existing Commission Policy

As noted above, although Staff supports a number of elements contained in the AG/ELPC NTG Framework as these are substantially similar to Staff's Modified Illinois NTG Framework, the element that Staff cannot support is the creation of "voting parties" as set forth in Item 2 of the AG/ELPC NTG Framework. (Staff Ex. 3.0C, 13-14; AG Ex. 1.1, 2; ELPC Ex. 1.4, 2; AG Ex. 2.0C, 6-7.) Item 2 of the AG/ELPC NTG Framework states, in relevant part:

> In cases where consensus among voting parties is reached in the SAG on an individual NTGR value by March 1 (PYt), that consensus NTGR value shall be deemed for the applicable program year (PYt+1), provided that the Program Administrators file the consensus NTGR values with the Commission in the TRM annual update docket no later than March 1 (PYt).

(AG Ex. 1.1, 2; ELPC Ex. 1.4, 2 (footnotes omitted).) Footnote 3 in Item 2 of the AG/ELPC NTG Framework states, in pertinent part:

> "Voting parties" are the program administrators, Staff, and other parties that have traditionally intervened in EEPS dockets and consistently participated in the SAG. These are AG, NRDC, ELPC and CUB. However, voting members cannot also be subcontractors in Section 8-103/104 efficiency programs.

(AG Ex. 1.1, 2; ELPC Ex. 1.4, 2.) Program administrators are defined in the IL-TRM and IL-TRM Policy Document as consisting of the utilities (Ameren Illinois, ComEd, Nicor Gas, and Integrys (North Shore Gas and Peoples Gas)) and DCEO. (IL-TRM Policy Document, 4.) Thus, the voting parties under the AG/ELPC NTG Framework include: program administrators (i.e., Ameren Illinois, ComEd, DCEO, Nicor Gas, Integrys), AG, CUB, ELPC, ICC Staff, and NRDC. This could be interpreted as either 6 or 10 voting parties, depending on whether each program administrator is allowed to vote on proposed NTG values for other program administrators. It is important to point out that the AG/ELPC NTG Framework requires consensus to be reached among all voting parties. (AG Ex. 1.1, 2; ELPC Ex. 1.4, 2.) "Consensus means that no party indicates they oppose a specific NTGR value enough to contest it before the Commission." (AG Ex. 1.1, 2; ELPC Ex. 1.4, 2; Staff Ex. 3.1, 3.) In other words, if one of the voting parties opposes a specific NTGR value enough to contest it, then consensus would not be reached. While the current proposal requires consensus, the establishment of voting parties in this proceeding could lead to the establishment of voting parties in other contexts where the majority's position is adopted. The Commission has repeatedly declined to give SAG decision-making authority, and Staff is concerned that the development of voting parties in this proceeding would be the first step toward such a structure. *See, e.g.,* ICC Order Docket No. 10-0568 at 86.

Mr. Mosenthal's explanation for the creation of voting parties is as follows:

> My intent is not one of limiting any particular party or to be exclusive. SAG meetings have traditionally been open to anyone to attend. I believe this is a good practice that allows for honest sharing of ideas and ensures greater transparency of SAG's deliberations. However, Staff's approach in practice could allow literally anyone to attend a SAG meeting and refuse to agree to a NTG consensus position regardless of whether that party has any particular knowledge or expertise on the issue, or whether they have ever intervened or otherwise been involved in energy policy in Illinois.
>
> In addition, many attendees at the SAG are subcontractors to another party. For example, consultants helping the program administrators design and plan programs, evaluators, and implementation contractors who sometimes are paid based on performance could conceivably vote under Staff's approach, and have a clear conflict of interest in regard to the ultimate NTG ratio selected. I believe it would be inappropriate to allow these parties a formal vote because they generally are attending the SAG as contractors to

> some other party that already has a vote. In addition, I believe it would be inappropriate for the evaluation consultants to have a vote. As the NTG framework describes, they are tasked with working together as independent parties to propose NTG values based on their professional expertise. To preserve this independence, I believe they should not then be in a position of actually advocating for any particular outcome. In addition, any party that has subcontracted with a utility to provide programs should not be permitted to vote on evaluation parameters. Finally, I believe the SAG facilitator should retain her independence to effectively facilitate and manage the SAG, rather than taking a formal position on substantive issues.

(AG Ex. 2.0C, 7-8.) Mr. Mosenthal provides no evidence to support his concern. There has been no showing that the utilities' subcontractors would oppose an updated NTGR value that was otherwise a consensus value. (Staff Ex. 3.0C, 14-15.) Subcontractors would not oppose an updated NTGR value that was otherwise a consensus updated NTGR value among SAG participants because objecting to a consensus NTGR value means that these subcontractors object to a NTGR value supported by their employer. (Staff Ex. 3.0C, 15.) This is not in the subcontractors' best interests. Indeed, Staff's experience to date during the development of the IL-TRM and the TRM Update Process demonstrates that subcontractors, including Evaluators and implementation contractors, do not attempt to delay that consensus-reaching process, even though they may not have necessarily agreed with the consensus that was reached. (Tr. 51-54, 57, Nov. 20, 2013; Staff Ex. 3.0C, 15.) Thus, there is no basis for introducing a drastic shift in the Commission-designed SAG changing its fundamental structure as a consensus building advisory group.

Staff is concerned about introducing a drastic shift in the SAG structure as proposed by the AG/ELPC NTG Framework. When the Commission ordered the SAG's creation in ICC Docket No. 07-0540, the Commission explicitly provided that the group include representation from a "variety of interests." Plan 1 Order at 24. The SAG is a voluntary group consisting of over thirty organizations, with new organizations requesting to participate in the SAG throughout the Plan. (Staff Ex. 3.0C, 15-16.) The AG/ELPC NTG Framework proposal to create a voting structure that is limited to a small portion of SAG participants is completely contrary to the inclusiveness that the SAG has provided to date. (Staff Ex. 3.0C, 16.) Indeed, this openness to all interested parties could likely be a reason why the participation in the SAG continues to grow. Id. Adoption of the AG/ELPC "voting structure" for NTG updates may serve to offend many SAG participants and discourage future participation by organizations. Id. The Commission should reject the proposal to significantly shift the structure of the SAG process to make certain SAG participants more equal than others.

Mr. Mosenthal indicates that "if any other party or parties that fits that criteria were to join and become more active and desire to participate in voting on NTG consensus issues, I would support that right, so long as they do not have a clear conflict such as being a contractor for a utility program." (AG Ex. 2.0C, 8.) The criteria used by Mr. Mosenthal to select voting parties includes: "entities have been regular, active members of the SAG and that, to date, do not have any obvious conflicts[.]" (AG Ex. 2.0C, 8.) Mr. Mosenthal does not set forth a process where the Commission would approve the addition of new voting parties. (Tr. 52, Nov. 20, 2013.) Presumably, a Commission determination that the party does not have any obvious conflicts would be necessary. Id. Based on the criteria proposed by Mr. Mosenthal, it seems that the utilities have obvious conflicts given that they are subject to penalties and potentially loss of the EE programs if they fail to meet the energy savings goals approved by the Commission, and lowering of a NTGR value makes it more difficult to reach such goals.

(Tr. 52, Nov. 20, 2013.) Yet, Mr. Mosenthal includes the utilities as voting parties in the AG/ELPC NTG Framework.

It is also not clear how exactly the voting process would work if certain voting parties are unavailable to participate during NTG discussions. (Tr. 51, Nov. 20, 2013.) For example, if one of the special SAG voting parties spent no time reviewing any of the information contained in the NTG memorandums submitted by the Evaluators or if they failed to attend the SAG meetings where the proposed NTG ratios were discussed, it is not clear under the AG/ELPC NTG Framework whether their voting party status would be suspended for the program year, or whether they would be required to vote even though they failed to participate throughout the entire NTG update process. AG witness Mosenthal expresses concerns about allowing any SAG participant the right to refuse to agree to a NTG consensus position regardless of whether that party has any particular knowledge or expertise on the issue, yet Mr. Mosenthal's creation of voting parties makes no assurances that such voting parties have any particular knowledge or expertise on the NTG issues for which they would be voting on. (AG Ex. 2.0C, 7.)

Without designating specific voting parties, it will be possible to determine whether consensus has been reached regarding updated NTGR values. Indeed, this approach is consistent with the existing Commission-approved process for annually updating the IL-TRM. (*See,* IL-TRM Policy Document, 6, 8.) The Commission-adopted IL-TRM Policy Document states: "Through the annual TRM Update Process, SAG participants shall make good faith efforts to reach consensus on all TRM Updates. Once consensus develops <u>at the SAG level</u>, the TRM Administrator will include the changes in the Updated TRM that is submitted to the Commission for approval." (IL-TRM Policy

Document, 8 (emphasis added).) The SAG is currently able to develop and reach consensus on IL-TRM Updates without modifying the SAG structure and without identifying specific voting parties as evidenced by the Commission's approval of the consensus IL-TRM Version 2.0: "The Commission agrees with Staff that the IL-TRM Version 2.0 filed in this docket as an attachment to the Staff Report in this docket was arrived at using the Commission-mandated process, it is a consensus document, and it is consistent with the Commission's Orders and the TRM Policy Document adopted by the Commission." ICC Order Docket No. 13-0437 at 4 (Nov. 6, 2013) (footnote omitted). Staff's Modified Illinois NTG Framework includes a process where any interested party must dissent in writing by a specific date to indicate there are non-consensus updated NTGR values. (Staff Ex. 3.1.) Further, the independent Evaluators are tasked with providing meeting notes after the NTG update meetings which can clearly document consensus and non-consensus NTGR values, which is somewhat comparable to the role the TRM Administrator takes in the TRM Update Process.

(ii) Other Problems with the AG/ELPC NTG Framework

Some of the other problems with the AG/ELPC NTG Framework include: (1) the TRM annual update docket specified for the annual filing of deemed NTGR values is not open on March 1; (2) the date to reach consensus by is the same date that the annual filing of deemed NTGR values must occur; (3) the deadline for the non-residential program NTGR recommendations from the Evaluators does not allow for incorporating the previous year's evaluation results; (4) the formula used to resolve non-consensus NTGR values is internally inconsistent within the AG/ELPC NTG Framework; and (5) the equation used for resolving non-consensus NTGR values has undefined terms.

While these are not the only concerns associated with the AG/ELPC NTG Framework, these five problems are real problems which would significantly frustrate any attempts at implementing the AG/ELPC NTG Framework. Staff's Modified Illinois NTG Framework (Staff Ex. 3.1) is, to the best of Staff's knowledge, free of these problems and provides a framework that would be workable in practice. Each of these issues is described in more detail below.

(a) The TRM Annual Update Docket specified for the annual filing of deemed NTGR values is not open on March 1.

The AG/ELPC NTG Framework proposal requires the utilities to file the deemed NTGR values in the TRM annual update docket by March 1, and if such filing does not occur by that date, then the utilities are subject to retroactive application. (AG Ex. 1.1, 4; ELPC Ex. 1.4, 4.) The problem with this approach is that there is no guarantee, nor is it even envisioned in the Commission-adopted IL-TRM Policy Document, that the TRM annual update docket will even be open by March 1, potentially resulting in annual retroactive application of NTGR values for the utilities under the AG/ELPC NTG Framework. (Staff Ex. 3.0C, 19.) The adopted IL-TRM Policy Document states:

> In order to provide the Program Administrators adequate time for making these pre-program year changes, the consensus Updated TRM shall be transmitted to the ICC Staff and SAG by March 1st. The ICC Staff will then submit a Staff Report (with the consensus Updated TRM attached) to the Commission with a request for expedited review and approval. In the event that non-consensus TRM Updates exists, the TRM Administrator shall submit to the ICC Staff and SAG a Comparison Exhibit of Non-Consensus TRM Updates on or about March 1st. After receipt of the Comparison Exhibit of Non-Consensus TRM Updates, the ICC Staff would submit a Staff Report to the Commission to initiate a proceeding separate from the consensus TRM Update proceeding to resolve the non-consensus TRM Update issues.

(Staff Ex. 3.0C, 19.) There is no TRM update docket required to be open on March 1, the Updated TRM (consensus portion) is simply transmitted to SAG on that date, and the non-consensus portion of the Updated TRM is transmitted on or about March 1. Id. After receipt of the Updated TRM and submission of the Staff Report, the Commission would initiate the TRM Update proceeding at one of the Commission meetings following receipt of such Staff Report (after March 1). Id. Clearly, the AG/ELPC NTG Framework in this regard is unworkable in practice given the annual TRM Update proceeding is not even envisioned to have been initiated by the Commission by the March 1 deadline specified in their framework. Id. Staff's Modified Illinois NTG Framework resolves this issue by requiring the utilities to file the deemed NTG values in ICC Docket No. 12-0528, which is the docket in which the Commission approved the IL-TRM Version 1.0. (Staff Ex. 3.1, 3:10.) The utilities all file TRM-related evaluation research findings in that docket as well. (IL-TRM Policy Document, 8.) The filing of all deemed updated NTG values in that docket will enable parties to easily find the deemed NTG values and keep track of the NTG values as they are updated over time for all the Illinois utilities.

(b) The date to reach consensus by is the same date that the annual filing of deemed NTGR values must occur.

The AG/ELPC NTG Framework provides that parties are allotted until March 1 to reach consensus and it also provides that the deemed NTGR values must be filed by March 1 or the utilities will be subject to retroactive application of NTGR values. In the event that consensus is actually reached on March 1, the parties would need time to revise relevant documents to incorporate the consensus reached before they actually file them in a docket. (Staff Ex. 3.0C, 19.) The AG/ELPC NTG Framework proposal is unworkable in this regard because it provides no time to revise documents to reflect the consensus reached. (AG Ex. 1.1, 4; ELPC Ex. 1.4, 4.) Staff's Modified Illinois NTG Framework resolves this issue by specifying that parties are allotted until February 20 to reach consensus, and it provides time after that date to prepare the filing of deemed NTGR values. (Staff Ex. 3.1, 3, 5.) Specifically, the utilities are provided until March 5 to file the deemed NTGR values or the utilities will be subject to retroactive application of NTGR values. (Staff Ex. 3.1, 3:10, 5:10.)

(c) The deadline for the non-residential program NTGR recommendations from the Evaluators does not allow for incorporating the previous program year's evaluation results.

The AG/ELPC NTG Framework requires the Evaluator's memorandum for all NTGRs to be submitted by November 1. (AG Ex. 1.1, 3; ELPC Ex. 1.4, 3.) The Illinois Evaluators note that they can commit to providing draft NTGR results by December 1 for non-residential programs, not November 1. (Staff Ex. 1.2, 1.) Thus, under the AG/ELPC NTG Framework it is likely that the initial Evaluator's memorandum will not reflect the most recent findings with respect to estimating NTGRs for the utilities' non-residential programs. (Staff Ex. 3.0C, 20.) Given this problem with the AG/ELPC NTG Framework, the AG indicates support for Staff's proposal in this regard. (AG Ex. 2.0C, 4.)

(d) The formula used to resolve non-consensus NTGR values is internally inconsistent within the AG/ELPC NTG Framework.

The AG/ELPC NTG Framework provides for two different approaches in the case an individual NTGR value is determined to be non-consensus. (Staff Ex. 3.0C, 17.) This inconsistency can be seen by comparing Item 3 of the "Narrative Explanation of the

Modified NTG Framework" to Item 8 of the "Proposed Timeline." (AG Ex. 1.1, 2-3; ELPC Ex. 1.4, 2-3.) Item 3 of the "Narrative Explanation of the Modified NTG Framework" states:

> In cases where consensus is not reached on an individual NTGR value by March 1 (PYt), the NTGR value for the applicable program year (PYt+1) shall be the <u>average of the last two available evaluated NTGR values from prior years</u> (or only one year if that was the first evaluated year of the program available), provided that the Program Administrators file the non-consensus NTGR values with the Commission for information purposes in the TRM annual update docket no later than March 1 (PYt). In the event there is non-consensus on an individual deemed NTGR value and there are no Illinois evaluations available, the Program Administrators shall file the non-consensus positions and rationales, and request the Commission rule within 90 days on the deemed NTGR to be used for PYt+1.

(AG Ex. 1.1, 2; ELPC Ex. 1.4, 2 (emphasis added).) Staff interprets the emphasized text to mean that the deemed NTGR value is the average of evaluated NTGR values that are *currently available* (e.g., $NTGR_{PYt+1}=(NTGR_{PYt-1}+NTGR_{PYt-2})/2$) at the time the NTG deliberations are occurring in the program year (PYt). (Staff Ex. 3.0C, 17.) Based on Mr. Mosenthal's testimony, it appears that this specification was the intent of the AG/ELPC NTG Framework. (AG Ex. 2.0C, 4.) Indeed, this approach is consistent with Mr. Mosenthal's explanation of differences between Staff's and the AG/ELPC's proposal. <u>Id.</u> As is clearly evident, the proposed approach in Item 3 results in using NTGR values that are two years old and the utilities are aware what the average of the two old NTGR values are such that it effectively creates a lower bound and reduces the utilities' incentive to negotiate in good faith on its best estimate for a deemed NTGR value with the SAG. (AG Ex. 2.0C, 5; Staff Ex. 2.0, 19.) Importantly, Mr. Mosenthal supports Staff's approach, which is consistent with Item 8 of the "Proposed Timeline" of the AG/ELPC NTG Framework, as discussed below. (AG Ex. 2.0C, 4-5.) Item 8 of the "Proposed Timeline" states:

> In cases where consensus is not reached on an individual NTGR value by March 1 (i.e., a NTGR Objection Memo is received regarding an individual NTGR value and is not resolved by March 1), the NTGR value for the applicable program year (PYt+1) shall be deemed at the average of the evaluated NTGR values from PYt and PYt-1.[8] In the event there is non-consensus on an individual NTGR value and there are no Illinois evaluations available, an explanation of the non-consensus issue may be filed with the Commission with a request for resolution prior to June 1.

(AG Ex. 1.1, 3; ELPC Ex. 1.4, 3 (emphasis added).) The emphasized text, which is consistent with Staff's Modified Illinois NTG Framework, means that the deemed NTGR value for PYt+1 is the average of the evaluated NTGR values from the current program year (PYt) and the previous program year (PYt-1) (e.g., $NTGR_{PYt+1}=(NTGR_{PYt}+NTGR_{PYt-1})/2$). (Staff Ex. 3.0C, 18.) The proposed approach in Item 8 provides for the utilities to know one of the NTGR values and in certain cases it may know both (e.g., AIC's PY5 Residential Lighting Program NTGR was available before March in PY5). Id. But generally speaking, the utilities would know one of the NTGR values and have partial retrospective application of the NTGR evaluated for PYt under Item 8. (Staff Ex. 2.0, 19.) Given the utilities are subject to three-year cumulative goals, not knowing the NTGR evaluated for PYt until several months later should still provide the utilities enough time to adjust their portfolios in a manner that helps ensure they can reach the three-year cumulative goals. (Staff Ex. 3.0C, 18.) In other words, the utilities do not face insurmountable risk under the partial retrospective application approach that would be applied only in instances where consensus cannot be reached. Id.

[8] For a program that only has one year of evaluated NTG then that single year will be used.

(e) The equation used for resolving non-consensus NTGR values has undefined terms.

The AG/ELPC NTG Framework is missing a definition for "Evaluated NTGR values." (Staff Ex. 3.0C, 20.) This is problematic as it could be interpreted in a variety of ways. Id. "Evaluated NTGR values" potentially could mean the NTGRs estimated from surveys of the utility's participating customers and trade allies, regardless of whether the Evaluator recommended the NTGR be a mix of secondary and primary data, or even if the Evaluator recommended to totally ignore a portion of the primary data. Id.

In contrast, Staff's NTG Framework proposal contains a definition for this phrase to eliminate this issue. (Staff Ex. 3.1, 3:fn 5.)

> In cases where consensus is not reached on an individual NTGR value by February 20 (i.e., a *Party's NTGR Objection Memo* is received regarding an individual NTGR value and is not resolved by February 20), the non-consensus individual NTGR value for the applicable program year (PYt+1) shall be deemed at the average of the evaluated NTGR values [fn] from PYt and PYt-1. [fn]

(Staff Ex. 3.1, 3 (footnotes omitted).) The term "evaluated NTGR values" as used in this context is defined in footnote five on page three of Staff Ex. 3.1: "Evaluated NTGR values are NTGR values estimated by the evaluators using only data collected from the Utility's customers and contractors in the Utility's service territory." Id. The Evaluators are allowed to estimate a NTGR value for PYt and PYt-1 by any means they determine appropriate within the constraints of the definition set forth in footnote five on page three of Staff Ex. 3.1. (Staff Group Cross Ex. 2, 31.) The use of the term "from" in the phrase "evaluated NTGR values from PYt" means the NTGR values were estimated by the Evaluators using survey data derived from program participants that participated during

PYt. Id. at 31-32. Similarly, the use of the term "from" in the phrase "evaluated NTGR values from PYt-1" conveys the fact that the survey data that the Evaluators use to estimate the NTGR value must arise out of customers who participated in the program during PYt-1. Id.

(e) Deemed NTGR Values for EPY7/GPY4

Given the timeframe in Staff's and the AG/ELPC's NTG Frameworks has passed for the first program year of Plan 3, the Commission should direct AIC to work with the SAG to reach consensus on NTGR values to deem for EPY7/GPY4 and include such NTGR values for EPY7/GPY4 in the remodeling of AIC's portfolio for its Revised Plan that should be filed as a compliance filing in this docket. The EPY7/GPY4 NTG discussion should initiate with a memorandum from AIC's existing Evaluator containing its initial recommendations for deeming NTGR values for EPY7/GPY4; this approach is consistent with the first step in both Staff's Modified Illinois NTG Framework and the AG/ELPC NTG Framework proposals.

B. ENERGY EFFICIENCY POLICY MANUAL

Mr. Mosenthal requests that the Commission direct AIC to work with the SAG on "[a]n Illinois Energy Efficiency Policy Manual, designed to streamline and encourage consistency on various program-related policies for review and approval by the Commission." (AG Ex. 1.0, 52.) Staff and the Company agree that the Commission should reject the development of such an undefined Policy Manual at this time. (Staff Ex. 3.0C, 25; Ameren Ex. 6.0, 26.) As an initial matter, it is not evident what problem the creation of such a Policy Manual is intended to fix. (Staff Ex. 3.0C, 25.) Indeed, the scope of the Policy Manual is not clearly defined, other than noting a broad-slated purpose that it would somehow "streamline and encourage consistency on various program-related policies[.]" (AG Ex 1.0, 52.) The undefined nature of such proposal and the potentially broad interpretation that could be construed from the terms, "various program-related policies," could be a significant source of contention in even the early development stages. (Staff Ex. 3.0C, 25.)

The Act recognizes that coordination and consistency may be valuable across electric and gas programs to the extent it reduces program or participant costs or improves program performance. 220 ILCS 5/8-104(k). Section 8-104 of the Act requires the Commission to solicit public comment on a plan "to foster statewide coordination and consistency between statutorily mandated natural gas and electric energy efficiency programs to reduce program or participant costs or to improve program performance[,]" and to report the Commission's findings to the General Assembly. 220 ILCS 5/8-104(k). The Commission has already complied with this directive earlier this year. (Staff Ex. 3.0C, 26.) The Commission's report to the General Assembly appears to offer the Commission's view that existing efforts, including the SAG process, are sufficient. (Staff Ex. 3.0C, 26.)

Notwithstanding the electric and gas coordination and consistency provision, the statutes also recognize that each utility's plan will likely not be consistent with other utilities' plans. 220 ILCS 5/8-103(f). Instead, it would be more appropriate to tailor each utility's plan to the characteristics of its specific service territory. (Staff Ex. 3.0C, 26.) Section 8-103 of the Act states, "[e]ach utility's plan shall set forth the utility's proposals to meet the utility's portion of the energy efficiency standards … and the demand-response standards … <u>taking into account the unique circumstances of the utility's service territory.</u>" 220 ILCS 5/8-103(f) (emphasis added); *see also,* 220 ILCS 5/8-104(f). The record and findings in each utility's Plan filing docket provide sufficient guidance on how each utility should implement the EE programs in its unique service territory, and the creation of new policies midstream outside of the Plan filing dockets may serve to complicate and frustrate the utilities' existing EE program offerings to consumers. (Staff Ex. 3.0C, 26-27.)

Indeed, the Commission's Plan 1 Order states:

> This Commission agrees that coordination between Ameren and ComEd, as well as with DCEO, when such coordination reduces costs or administrative burdens, or, when such coordination would improve program performance, is desirable. We encourage the utilities and DCEO to coordinate as much as possible. However, we decline to require the utilities to do so. There are obvious differences in the territories of the two utilities regarding many items, including, but not limited to, labor costs, housing structure, population density, and, even topography. The utilities must be able to retain the flexibility to react appropriately to those differences.

ICC Order Docket No. 07-0539 at 35-36 (Feb. 6, 2008) ("Plan 1 Order").

The SAG has created a TRM Policy Document, which is a policy manual concerning policy issues limited to the TRM. (Staff Ex. 3.0C, 27.) The SAG, Staff, and Commission have expended a great deal of effort and time on the creation and adoption of this TRM Policy Document. (Staff Ex. 3.0C, 27.) Creating a Policy Manual that would require "consistency on various program-related policies" for all Illinois utilities would impose an undue and unnecessary burden on all parties and would divert resources from more important matters such as ensuring the programs are running effectively and updating the IL-TRM. (Staff Ex. 3.0C, 27.)

Finally, the development of a Policy Manual is expected to be a significant endeavor requiring significant resources to create, and as noted by the AG, there have been instances over the last Plan in which the SAG has not followed through with its existing responsibilities as directed by the Commission. (AG Ex. 1.0, 38; *see also,* Staff Ex. 1.3, 19.) Thus, it would be appropriate for the SAG to focus on accomplishing its existing responsibilities, rather than devote significant SAG resources to create a Policy Manual. (Staff Ex. 3.0C, 27.) SAG has enough duties dealing with the annual TRM and NTG updates and reviewing the utilities' quarterly reports and program changes such that it should concentrate on those given the responsibility the Commission has previously directed the SAG to undertake. (AG Ex. 1.0, 51.) Accordingly, the Commission should not adopt Mr. Mosenthal's proposal to create a Policy Manual at this time. (Staff Ex. 3.0C, 28.) AIC agrees with Staff's position. (Ameren Ex. 6.0, 26.) Accordingly, the Commission should decline to adopt this recommendation.

While Staff agrees there are benefits to having consistency among the utilities and DCEO in NTG policies and TRC definition policies, Staff does not agree there are benefits to having the SAG develop an undefined Policy Manual addressing issues such as prudence which the Commission has effectively evaluated for years. (Tr. 61, Nov. 20, 2013.)

1. Consistency in NTG Approaches

While Staff opposes the SAG undertaking the development of an undefined Policy Manual, Staff supports the development of consistent NTG methodologies. (Tr. 61, Nov. 20, 2013.) It would be valuable to have the Evaluators collaborate to reach consensus on the best approaches to assessing NTG in particular markets. (Tr. 47-49, Nov. 20, 2013.) It would help alleviate contention for spillover estimation approaches. During Plan 1, the Evaluators collaborated to develop a consistent approach to estimating NTG for the non-residential EE programs. However, alternative approaches are currently being discussed and implemented by the Evaluators for the non-residential EE programs. While consistency has occurred for many of the non-residential EE programs during Plan 1, the fact that alternative approaches are currently being implemented during Plan 2, a Commission directive is warranted to have the Evaluators collaborate to reach consensus on the best approaches to assessing NTG in particular markets for both residential and non-residential EE programs. Further, historically there has not been consistency with respect to estimation of residential program NTG ratios and this inconsistency has been subject to significant controversy, and creates concerns regarding the independence of certain Evaluators. Thus, to help mitigate the risk of compromising the independence of the Evaluators, the Commission should require consistent residential and non-residential NTG approaches take place for comparable EE programs offered by the utilities.

The Commission should be aware that the Staff and ELPC Proposed Modified NTG Frameworks allow for deeming a NTG value other than that which was evaluated, which is useful for cases where the evaluated number is inconsistent with other values. Given the inherent differences in the service territories of the utilities across the state as well as differences in the energy efficiency program guidelines, rebate amounts, and implementation approaches, in the event significantly different NTG results are found across comparable programs operated by different program administrators, the use of different NTG methods across program administrators provides limited useful information to parties concerning the source of such differences. Indeed, the memorandum containing the previously adopted NTG Framework expressed such concerns:

> The PY1 evaluated NTG ratios for Residential lighting are significantly different for Ameren and ComEd. While there are real differences in the demographics of their service territories that may have contributed to this difference, it is important to note that the utilities used different evaluation contractors and significantly different evaluation methodologies. As a result, there is little certainty about the attribution of these differences. We propose that wherever possible, joint and consistent statewide evaluations be performed. This will eliminate these uncertainties, allow for more direct comparison between [program administrators' ("PA's")] performance, as well as provide economies of scale and greater consistency and certainty to PAs about likely future evaluation results. We propose that standardized approaches to measuring freeridership and spillover be adopted in Illinois that ensure consistent measurement both across territories and over time. [fn]

(AG Ex. 1.1, 3-4, ICC Docket No. 10-0568.) The omitted footnote in the quoted text above states that "[a]n example of this exists in Massachusetts where all PAs have for roughly a decade used a standardized methodology and set of survey questions that were collaboratively developed to measure freeridership and spillover every year. This approach has proven to provide relatively stable results over time, and better elucidates differences between PAs that may result from different program approaches." Id. at 4.

Based on the concerns expressed regarding differences in the lighting program NTGR values between ComEd and AIC, the Commission directed the following: "The Commission also accepts Ameren's recommendation that Ameren, as well as ComEd, and the independent evaluators strive to understand differences in evaluation results and to reconcile differences not driven by differences in weather, market and customers." Plan 2 Order at 70. Despite this direction, Staff has found it extremely difficult to get the Evaluators to use consistent methodologies. (Tr. 49, Nov. 20, 2013.)

Thus, the Commission should direct AIC to require its Evaluators to collaborate with the other utilities' Evaluators to reach consensus on the best approaches to assessing NTG in particular markets for both residential and non-residential EE programs. The best approaches will not be inflexible but would be able to be tailored to appropriately assess the specifics of each of the utilities' EE programs, consistent with approaches adopted in other states. Further, the Commission should direct Staff to file the agreed upon approaches with the Commission as an appendix to the updated IL-TRM. It should be clear that this recommendation is not to create entirely new NTG approaches, but rather assess existing methods used in Illinois and adopt the best and most defensible method, or potentially combine certain components from the existing approaches to better represent the most defensible method. The Evaluators in Illinois have currently been working on this for business EE programs, so finalizing a consistent approach for the business programs should be able to be completed before the filing of the updated IL-TRM.

C. ALIGNING THE TIMING OF THE APPLICATION OF THE NET TO GROSS FRAMEWORK AND ILLINOIS TECHNICAL REFERENCE MANUAL

Mr. Mosenthal requests that the Commission direct AIC to work with the SAG on "[i]mproving the evaluation, measurement and verification (EM&V) process so that [the Evaluators'] reports are produced in a timely fashion to inform TRM and NTG updates[.]" (AG Ex. 1.0, 52.) Staff agrees with this concept and in fact Staff has been working to encourage the Evaluators to deliver EM&V reports concerning TRM and NTG updates in a more timely fashion. (Staff Ex. 3.0C, 24.) Accordingly, rather than Commission directing AIC to work with the SAG concerning this evaluation timing issue as requested by Mr. Mosenthal, Staff recommends the Commission resolve the matter in this docket and adopt the workable timelines suggested by the Evaluators for TRM and NTG updates such that AIC can have those incorporated in its evaluation contracts after approval of the Plan. (Staff Ex. 1.2, 1.)

One of the apparent drivers of the date the NTG results are produced is the date the Evaluators finally receive the final EE program tracking system information from the utilities after the program year has ended. (Staff Ex. 3.0C, 34; Staff Ex. 1.3, 2-3.) Since the finalization of the tracking system for the non-residential programs apparently takes longer than for residential programs, producing the NTG results for the non-residential programs also takes longer, namely December 1 for non-residential programs and November 1 for residential programs, which supports why a two-track approach for the NTG updates is appropriate. (Staff Ex. 3.0C, 24; Staff Ex. 1.0, 33-35; Staff Ex. 1.3, 2-3.) Indeed, Mr. Mosenthal supports such an approach. Because final tracking system information is not needed for updating the TRM, the Evaluators suggest that the annual TRM Update Process can begin much earlier (i.e., July 1, with much of the work due from the Evaluators on August 1 and October 1) than the process for updating NTG ratios (November 1 for residential NTG ratios and December 1 for non-residential NTG ratios). (Staff Ex. 3.0C, 25.)

Importantly, all of the utilities' Evaluators have worked together and recently produced a single set of suggested timelines that could work well in updating the deemed values for both the TRM and NTG ratios on an annual basis for Illinois. (Staff Ex. 1.2, 1.) Thus, for the sake of resolving the issue raised by the AG in this docket which would free up limited SAG resources for addressing unresolved matters that actually require SAG's attention, the Commission should adopt the Evaluators' suggested EM&V schedules for TRM and NTG updates as set forth in Staff Ex. 1.2.

D. Portfolio Flexibility

It is critical the Company is granted flexibility to prudently respond to changing circumstances over the course of the Plan. (Staff Ex. 1.0, 31.) AIC should include a discussion of how it uses its flexibility in its quarterly ICC activity reports submitted to the Commission. (Staff Ex. 1.0, 31.) Staff supports AIC's flexibility request in this regard only if the Commission explicitly requires the following: (1) AIC is directed to prudently respond to changes (e.g., TRM, NTG, market) in the implementation of its programs; (2) AIC is directed to spend all funding to the extent practicable on cost-effective energy efficiency measures in order to exceed the modified savings goals; (3) AIC is directed to avoid over-promoting cost-ineffective measures so as to help ensure participation of these cost-ineffective measures does not exceed expectations; (4) AIC is directed to provide cost-effectiveness screening results in its quarterly ICC activity reports for new measures the Company adds to its Plan during implementation; and (5) AIC is directed to explain how it responds to TRM, NTG, and other changes in its quarterly ICC activity reports it will file with the Commission in this docket. (Staff Ex. 3.0C, 7; Staff Ex. 1.0, 20.) The Commission denied to impose limits on AIC's request for flexibility in previous Plan dockets based on the information available at that time. The Plan 2 Order states:

> Ameren requests that the Commission grant it the flexibility to adjust all portfolio elements as need to achieve portfolio success. Staff supports Ameren's proposal, which it says proved successful in the first plan. While both the AG and NRDC-ELPC generally support the concept that Ameren should be granted flexibility, they recommend restrictions on Ameren's

> flexibility. As discussed elsewhere in this order, the SAG has proved quite effective thus far and Ameren insists it is committed to continued participation in the SAG. Additionally, it does not appear that any party is suggesting that Ameren has abused the flexibility that the Commission has thus far granted it. Were Ameren to abuse the flexibility granted it, the Commission would, of course, take steps necessary to address such a situation. Given the that Ameren is ultimately responsible for achieving portfolio success, and the other circumstances present, it is not clear that the limitations on Ameren's flexibility proposed by the AG or NRDC-ELPC are necessary, at this point in time. The Commission once again grants Ameren the flexibility to administer its programs in the same manner and subject to the same requirements that it has been granted to administer its previous plans. (See, Final Order, Docket No. 07-0539, Order at 26, (Feb. 6, 2008)) The Commission believes the level of flexibility granted in Plan 1 is sufficient to address Intervenors' concerns and therefore approve the same level of, and application of, flexibility as granted in Docket No. 07-0539.

ICC Order Docket No. 10-0568 at 86 (Dec. 21, 2010). AIC cites to past Orders supporting flexibility, noting that AIC has not abused it. (Ameren Ex. 10.0, 7.) Staff, however, believes that AIC has not used this flexibility prudently, particularly in the addition of cost-ineffective measures to Plans after the plans were approved. (Staff Ex. 1.1, 18; Ameren Resp. to Staff DR JLH 3.04.) Accordingly, the Commission should order AIC to follow certain directives, as outlined above and further discussed below, during the implementation of its Plan.

In order to ensure ratepayers receive the net benefits they deserve, the Commission should order AIC to limit the participation of cost-ineffective measures to no more than the levels proposed in its Plan and to provide cost-effectiveness screening results in its quarterly ICC activity reports for new measures the Company adds to its Plan during implementation. (Staff Ex. 1.0, 20; Staff Group Cross Ex. 2, 2-4.) Currently, AIC's request for flexibility includes the ability to add new measures to the Plan during implementation, without providing the Commission with the cost-effectiveness screening results for such measures in its quarterly ICC activity reports. (Staff Ex. 1.3, 18; Ameren Resp. to Staff DR JLH 3.04; Staff Group Cross Ex. 2, 2-4.) The Company should be required to provide the cost-effectiveness screening results in the quarterly ICC activity reports to ensure the Company is transparent regarding the addition of new EE measures to its Plan. Staff believes this additional transparency will help ensure the Company does not add cost-ineffective measures to the Plan after Commission approval to the detriment of ratepayers.

AIC's stated purpose of its request for flexibility is to enable the Company to achieve its savings goal and maximize cost effectiveness. (Ameren Ex. 10.0, 6.) This stated purpose of maximization of cost effectiveness seems inconsistent with AIC's position against Staff's proposal. (Ameren Ex. 10.0, 4.) As AIC witness Goerss states:

> Ameren Illinois already files quarterly reports with the ICC that include key activities, key concerns, and activity reports for each of the programs being implemented. To the extent Staff seeks Ameren Illinois to continue to provide this level of detail during Plan 3, Ameren Illinois agrees to do so. It is unclear what else Staff would like included in the reports, as Ameren Illinois uses its Commission-approved flexibility when either modifying its portfolio or maintaining it.

(Ameren Ex. 6.0, 20.) AIC's existing quarterly ICC activity reports have not sufficiently explained changes to the portfolio. They also have not documented AIC's decisions to exercise this flexibility. The Commission should order AIC to limit the implementation of the other cost-ineffective measures included in the Plan filing to the participation estimates included in the Plan. (Staff Ex. 1.0, 19-21; *see also,* Staff Ex. 1.3, 9-11.)

E. Application of Total Resource Cost Test

AIC's request concerning maintaining a positive portfolio level TRC is described by AIC witness Robert D. Obeiter:

> [W]ith respect to my testimony on allowing flexibility to make programmatic changes, I believe that program administrators should be accountable at the portfolio level to ensure cost effectiveness. Therefore, it should be Ameren Illinois' object to maintain a positive portfolio TRC, rather than do so at the measure or even program level.

(Ameren Ex. 5.0, 34:727-733 (emphasis added).) AIC's Plan states:

> As a result of these factors, in addition to the status of program development and implementation, a measure or program level TRC is subject to significant changes in cost-effectiveness. AIC formally requests that the Commission recognize this fluctuation, and that planning estimates may prove inaccurate, and reaffirm its determination from the Plan 1 and 2 Orders whereby it is the utility's objective and accountability to maintain a portfolio level positive TRC regardless of measure or program level TRC.

(Ameren Ex. 6.1, 51-52 (emphasis added).)

Although the term "accountability" is used in AIC's Plan, it is clear based on Ameren's Resp. to Staff DR JLH 2.08 that AIC is not requesting to be held accountable for ensuring the portfolio is cost-effective. (Staff Ex. 1.3, 7; Ameren Resp. to Staff DR JLH 2.08.) I believe AIC has erred in its interpretation of past Commission Orders. It is clear that a minimum requirement of Plan approval is that the portfolio has to pass the TRC test in order to be approved by the Commission. 220 ILCS 5/8-103(f)(5); 220 ILCS 5/8-104(f)(5). It is this requirement that the Commission has confirmed in past Orders. Adding cost-ineffective measures and programs increases the risk that the portfolio will be cost-ineffective and will not provide net benefits to ratepayers, thereby increasing the risk that the policy objectives set forth in the EE statutes to reduce direct and indirect costs to consumers will not be achieved. 220 ILCS 5/8-103(a). Indeed, a key portfolio objective was to incorporate cost-effective programs (Ameren Ex. 6.1, 7) and a key modeling assumption was to screen all measures for the TRC test (Ameren Ex. 6.1, 8).

In order to ensure the portfolio is cost effective and produces the net benefits to ratepayers envisioned by the EE statutes, AIC should stay apprised of and respond prudently to information concerning measure and program level cost-effectiveness during the course of implementing its portfolio to help ensure net benefits are maximized for Illinois ratepayers within the constraints of the other requirements set forth in statute. (Staff Ex. 1.0, 21; Staff Cross Ex. 2, 6-8.) The Commission should order AIC to do so. (Staff Ex. 1.0, 21.)

AIC's Plan includes some measures that do not pass the TRC test, but all programs pass the TRC test, and the planned portfolio also passes the TRC test. (Ameren Ex. 1.0, 9:194-197.) Including cost-ineffective measures within EE programs increases the risk that the entire portfolio may become cost-ineffective. (Staff Ex. 1.0, 19.) Staff concurs in principle with the AG's proposal concerning reasons to allow AIC to pursue certain proposed non-cost-effective measures in its Plan. (AG Ex. 1.0, 47-49.) Nevertheless, the addition of a cost-ineffective measure serves to reduce net benefits to ratepayers and this makes it more difficult for the policy objectives set forth in the EE statutes to be realized (i.e., direct and indirect costs to consumers shall be reduced through investment in cost-effective EE measures). 220 ILCS 5/8-103(a); 220 ILCS 5/8-104(a). Section 8-103(a) of the Act states:

> It is the policy of the State that electric utilities are required to use cost-effective energy efficiency and demand-response measures to reduce delivery load. Requiring investment in cost-effective energy efficiency and demand-response measures will reduce direct and indirect costs to consumers by decreasing environmental impacts and by avoiding or delaying the need for new generation, transmission, and distribution infrastructure. It serves the public interest to allow electric utilities to recover costs for reasonably and prudently incurred expenses for energy efficiency and demand-response measures.

220 ILCS 5/8-103(a). Similarly, Section 8-104(a) of the Act states:

> It is the policy of the State that natural gas utilities and the Department of Commerce and Economic Opportunity are required to use cost-effective energy efficiency to reduce direct and indirect costs to consumers. It serves the public interest to allow natural gas utilities to recover costs for reasonably and prudently incurred expenses for cost-effective energy efficiency measures.

220 ILCS 5/8-104(a).

Two of the approximately fifty cost-ineffective measures AIC proposed in its initial Plan filed as Ameren Ex. 1.1 were forecasted to reduce ratepayer welfare by over $1 million each based on AIC's forecasted participation estimates: Furnace 97% AFUE [-$1,123,441=(-$609x1,845)] and Interior LED Lamps and Fixtures [-$1,590,364]. (Staff Ex. 1.3, 11; Ameren Resp. to Staff DR JLH 2.09 Attach.) AIC has no plans to limit participation for cost-ineffective measures. (Staff Ex. 1.3, 12; Ameren Resp. to Staff DR JLH 2.10.) This is important because AIC's proposed Residential HVAC Program (which contains the cost-ineffective Furnace 97% AFUE measure among other measures) was barely forecasted to be cost-effective with a TRC benefit-cost ratio of 1.01 in AIC's original filed Plan. (Ameren Ex. 2.0, 27.) Thus, the HVAC program could easily become cost-ineffective if AIC's participation estimate for the Furnace 97% AFUE measure is underestimated. Fortunately, in response to the AG's concerns, AIC has removed this measure from its Plan filed as Ameren Ex. 6.1 and the HVAC Program is now modeled with a TRC ratio of 1.18. (Ameren Ex. 7.0, 2.) Nevertheless, in order to ensure ratepayers receive the net benefits they deserve, the Commission should order AIC to limit the participation of cost-ineffective measures to no more than the levels proposed in its Plan and to provide cost-effectiveness screening results in its quarterly

ICC activity reports for new measures the Company adds to its Plan during implementation. (Staff Ex. 1.0, 20; Staff Group Cross Ex. 2, 2-4.)

F. Aligning Savings Goals According to Changes in Values

AIC initially requested adjustment to savings goals based on "program changes" and "with any change in program design." (Ameren Ex. 5.0, 5; *see also*, Ameren Resp. to Staff DR JLH 3.15, 3.16, 4.01, NRDC DR 2.10.) However, due to the inherent problems associated with this component of its request as explained by Staff, AIC has since withdrawn this component of its proposal. (Ameren Ex. 6.0, 11; Staff Ex. 3.0C, 9.) AIC continues to request annual adjustments to savings goals based on Commission-approved IL-TRM and NTG changes. (Ameren Ex. 6.0, 11.) Staff supports AIC's request in this regard only if the Commission explicitly requires the following: (1) AIC is directed to prudently respond to changes (e.g., TRM, NTG, market) in the implementation of its programs; (2) AIC is directed to spend all funding to the extent practicable on cost-effective energy efficiency measures in order to exceed the modified savings goals; (3) AIC is directed to avoid over-promoting cost-ineffective measures so as to help ensure participation of these cost-ineffective measures does not exceed expectations; (4) AIC is directed to provide cost-effectiveness screening results in its quarterly ICC activity reports for new measures the Company adds to its Plan during implementation; and (5) AIC is directed to explain how it responds to TRM, NTG, and other changes in its quarterly ICC activity reports it will file with the Commission in this docket. (Staff Ex. 3.0C, 7; Staff Ex. 1.0, 20.) If the Commission adopts this approach to adjustable savings goals, it should direct AIC to file a public version of the spreadsheet that demonstrates the savings forecasted in the approved Plan match the calculated savings in the spreadsheet listing all the measures with the associated IL-TRM measure codes. It appears that AIC has attempted to comply with this requirement in its filing of Ameren Exhibit 7.1 (and electronically serving the spreadsheet version) as Staff had recommended in direct testimony. (Staff Ex. 1.0, 28:674-678; Ameren Ex. 7.1, 6-29.) However, the spreadsheet AIC filed is missing the TRM measure codes that form the basis for each of the measure assumptions. The TRM measure codes are necessary to include in such filing in order to transparently convey the version of the TRM measure that was used in AIC's calculations as some measures contain numerous inputs and it would be difficult for a party to determine which version of the TRM was used. In order to accurately track the changes to the savings goals and the reasons for the adjustments, AIC needs to include the TRM measure codes next to each measure in its filing. In the alternative, should the Commission decline to adopt this approach to adjustable savings goals, the Commission should still adopt the five directives outlined above.

Certain parties oppose annually adjusting AIC's savings goals based on NTG and TRM changes. (AG Ex. 1.0, 42-43; NRDC Ex. 1.0, 4, 27-28; Tr. 79-80, Nov. 20, 2013.) The main concerns of the parties relate to (1) AIC will not make prudent program adjustments; (2) AIC will not spend leftover funds on additional cost-effective energy efficiency once it reaches the modified energy savings goals; and (3) AIC's proposal would be excessively burdensome to administer. Id. Each of these issues will be addressed in turn below.

As noted above, the basis of many parties' concerns is that AIC will not make prudent program adjustments based on the revised TRM and NTG ratios if the savings goals are also allowed to adjust. (AG Ex. 1.0, 40, 42.) Staff shares this concern, and indicated in testimony that Staff would only support annual adjustments to savings goals based on TRM and NTG changes if the Commission explicitly required that AIC be held accountable to prudently respond to such changes in the implementation of its programs. (Staff Ex. 1.0, 28-29; Staff Ex. 3.0C, 7.) Further, directing AIC to explain how its responds to changes in its quarterly ICC activity reports it files with the Commission will increase transparency to help ensure AIC is prudently responding to such changes.

Another concern parties have with respect to annually adjusting AIC's savings goals is that it will make it extremely easy for AIC to achieve the modified goals and that once AIC achieves those modified goals, AIC will shut down programs mid-year and not spend all the budgeted funds on cost-effective EE measures and deprive Illinois customers of the benefits they deserve. (Staff Ex. 3.0C, 7.) If the Commission approves goals in this proceeding for which AIC must strive hard to achieve, then any change in goals resulting from changes in NTG and TRM values will still result in modified goals that AIC must strive hard to achieve. Id. Additionally, AIC is at risk with respect to ensure program participation is sufficient to achieve modified goals. Id. Adoption of Staff's recommendation concerning the Commission directing AIC to spend all funding to the extent practicable on cost-effective energy efficiency measures in order to exceed the modified goals should completely eliminate the parties' concerns in this regard. Id.

Several parties claim that AIC's proposal to annually adjust savings goals would be excessively burdensome to administer. (AG Ex. 1.0, 42-43; NRDC Ex. 1.0, 4.) Staff agrees that the component of AIC's proposal to annually adjust savings goals based on subjective changes to program design would be excessively burdensome to administer and it is much more subject to gaming. (Staff Ex. 3.0C, 10.) This component of AIC's proposal seems somewhat comparable to the AG's proposed flexibility limitations. (AG Ex. 1.0, 32-33.) As noted above, in its rebuttal testimony, AIC has withdrawn this component of its proposal. (Ameren Ex. 6.0, 11.) Annually adjusting the savings goals based strictly on changes to the IL-TRM and NTGRs is administratively easy to implement as it involves simply changing an assumed NTG or TRM value in a spreadsheet to calculate the revised goals. (Staff Ex. 3.0C, 10.) As noted above, if the Commission adopts this adjustable savings goal approach, it should direct AIC to file a public version of the spreadsheet that demonstrates the savings forecasted in the approved Plan match the calculated savings in the spreadsheet listing all the measures. The Commission-approved changes to the IL-TRM and NTGRs would be the values that change in the spreadsheet annually. The Commission should direct AIC to file the revised spreadsheet containing the changes to NTG, IL-TRM values, and savings goals in this docket no later than May 1 of each program year in advance of those values taking effect on June 1. To the extent the NTG ratio is unavailable by that date; the Commission should direct the Company to file a revised spreadsheet once the changed NTG ratio is known.

In ComEd's Plan 2 Docket No. 10-0570, the Commission agreed with a stipulation entered into by all parties that modified the savings goals such that they would adjust annually based on changes in the NTG ratio for its residential lighting program and for other reasons. (Staff Ex. 3.0C, 7.) The Commission found that the provisions of the stipulation were consistent with Section 8-103 of the Act, reasonable, and in the public interest, and specifically that it was appropriate and reasonable "to provide that the goals be adjusted should certain revenues either not materialize or be greater than expected[.]" ICC Order Docket No. 10-0570 at 35-36 (Dec. 21, 2010). Given the Commission has previously found that annual modification of savings goals is consistent with Section 8-103 of the Act, the Commission should approve adjustable savings goals in this docket subject to the conditions described herein. It is critical that the Commission adopts this approach such that AIC's incentive to annually oppose changes to the IL-TRM and NTG ratios that reduce savings will be eliminated and the deemed values will reflect the best estimates of savings and provide the proper incentives for spending ratepayer funds in Illinois. Adoption of this approach will also reduce litigation in the annual IL-TRM Update proceeding and facilitate reaching consensus on the annually Updated IL-TRM.

G. Banking of Savings

H. CFL Carry-forward Savings

Mr. Mosenthal indicates there has been some uncertainty with respect to how to calculate CFL carryover (i.e., CFL carry-forward) savings. (AG Ex. 1.0, 27.) Staff agrees there previously was some degree of uncertainty concerning CFL carryover calculations, but to a large degree it has been addressed and clarified in the most recent update to the IL-TRM. (Staff Ex. 3.0C, 11.) Nevertheless, Mr. Mosenthal requests getting rid of CFL carryover. (AG Ex. 1.0, 26.) If Mr. Mosenthal wants to remove CFL carryover from the IL-TRM, then the AG should submit a recommendation for a TRM Update through the TRM Update Process outlined in the TRM Policy

Document. (Staff Ex. 3.0C, 11.) It is inappropriate to raise this issue in a single utility's three-year plan filing docket, when the IL-TRM impacts all the Illinois program administrators. (Staff Ex. 3.0C, 11.) Thus, the Commission should decline to rule on Mr. Mosenthal's request to get rid of CFL carryover in this docket. Id.

Several parties recommend that AIC should include an estimated amount of savings expected from CFL carryover from CFLs purchased in PY5 and PY6 in the savings estimates presented in its Plan. (AG Ex. 1.0, 23-28; NRDC Ex. 1.0, 13-15.) AIC is required to follow the IL-TRM when submitting its Plan and thus estimating the amount of savings from CFL carryover bulbs should be included. (Staff Ex. 3.0C, 12.) AIC witness Goerss indicates that CFL carryover calculations are based on the NTGR estimated for the year the bulbs are installed. Id. Mr. Goerss' interpretation of CFL carryover calculations in this regard is incorrect; it is the NTGR estimated during the year of purchase that should be used. Id. However, the IL-TRM Version 2.0 does provide that the gross savings calculations for the CFL carryover bulbs should be based on the evaluated savings for the year the bulb is installed (i.e., the baseline determined for the installation year). Id.

I. CONTRACTING WITH INDEPENDENT EVALUATORS

Staff supports the adoption of the same provisions the Commission adopted in the Plan 2 Order concerning evaluator independence. (Staff Ex. 1.0, 23-24.) The Plan 2 Order contains certain provisions concerning evaluator independence on pages 68-69, as quoted below. The Plan 2 Order states:

> Generally, the parties and the Commission seem to agree the EM&V contractor independence is important in complying with Sections 8-103(f)(7) and 8-104(f)(8) of the Act. To ensure EM&V contractor independence, the

> Commission hereby adopts Ameren's and Staff's recommendations to include contract language consistent with that adopted in the Order on Rehearing in Docket No. 07-0539 (March 26, 2008). In addition, the Commission directs Ameren to hire its EM&V contractor consistent with the direction provided in the Order on Rehearing in Docket No. 07-0539 and file the appropriate compliance documents in Docket No. 10-0568. The Commission directs Ameren to continue the activities listed in its Plan to help preserve the independence of the evaluator. The Commission agrees with Staff that Ameren should ensure the data used in the independent evaluations can be made available to the Commission upon request. Further, Ameren is directed to instruct its evaluation contractor to submit draft EM&V reports to Ameren, the SAG, and Staff concurrently, and directs Ameren to include such a provision in its contract.
>
> Ameren currently proposes a modified three-year evaluation cycle that explicitly allows the independent evaluator to conduct less than one impact evaluation and less than one process evaluation every year, with a general goal of conducting one impact evaluation and one process evaluation for each program during each Plan cycle. Staff does not oppose Ameren's proposal subject to several conditions. The AG wants the Commission to adopt the SAS NTG framework that was the basis for the Settlement Stipulation in the ComEd case, Docket No. 10-0570. NRDC-ELPC urge Ameren to engage stakeholders through the SAG to develop an evaluation schedule for each program within the limitations of the evaluation budget.
>
> With regard to the AG's proposal, the Commission believes it would be problematic to impose on Ameren a settlement stipulation from a different proceeding to which Ameren has not agreed. While not specifically what the AG proposes, the Commission finds that Ameren's final proposal regarding the evaluation cycle is consistent with the AG's objectives. Similarly, the Commission believes that Ameren's final proposal adequately addresses the concerns expressed by NRDC-ELPC. The three conditions proposed by Staff, to which Ameren does not object, appear reasonable and they are hereby approved.

Plan 2 Order at 68-69. Given there are numerous references to the adoption of conditions recommended by certain parties or adopted in prior Orders within this passage, for the sake of clarity, Staff details the specifics of each provision the Commission should confirm in this Order to ensure independence of AIC's evaluators.

Each provision quotes the applicable orders, either Plan 1 Order (Docket No. 07-0539), Plan 2 Order (Docket No. 10-0568), or both.

<u>Provision 1:</u> The Plan 2 Order states: "To ensure EM&V contractor independence, the Commission hereby adopts Ameren's and Staff's recommendations to include <u>contract language consistent with that adopted in the Order on Rehearing in Docket No. 07-0539</u> (March 26, 2008)." ICC Order Docket No. 10-0568 at 68-69 (Dec. 21, 2010) (emphasis added). The referenced contract language in the Plan 1 Order on Rehearing states: "(5) any contract between [Ameren Illinois Company] and an independent evaluator shall provide that this Commission has the right to: approve or reject the contract; direct Ameren to terminate the evaluator, if the Commission determines that the evaluator is unable or unwilling to provide an independent evaluation; and approve any action by the utility that would result in termination of the evaluator during the term of the contract." ICC Order on Rehearing Docket No. 07-0539 at 4 (March 26, 2008).

<u>Provision 2:</u> The Plan 2 Order states: "In addition, the Commission directs Ameren to <u>hire its EM&V contractor consistent with the direction provided in the Order on Rehearing in Docket No. 07-0539 and file the appropriate compliance documents</u> in Docket No. 10-0568." ICC Order Docket No. 10-0568 at 69 (Dec. 21, 2010) (emphasis added). The referenced appropriate compliance documents provided in the Plan 1 Order on Rehearing states: "(3) [Ameren] shall file any Request for Proposals for its independent evaluator required by 220- ILCS 5/12-103(f)(7) within 10 days of its issuance, as a compliance filing in this docket; (4) [Ameren] shall submit any contract with an independent evaluator as a compliance filing in this docket within ten days of its execution". ICC Order on Rehearing Docket No. 07-0539 at 4 (March 26, 2008). The referenced "direction" provided in the Plan 1 Order on Rehearing states: "We note that the evaluator would not be "independent," as required by statute, if Ameren had total control over that evaluator. However, that does not mean that this Commission should be involved in the designing of an RFP, conducting interviews, and doing the many other tasks involved in hiring this evaluator. Rather, it means that this Commission has a supervisory capacity regarding the hiring and firing of this evaluator, meaning that Ameren must gain Commission consent to make the hiring and firing decisions regarding this evaluator. We further note that the approach taken by the AG/CUB for gaining Commission consent is a reasonable one. Ameren would make compliance filings in this docket regarding its contractual relationship with the evaluator, as is set forth above. Pursuant to this approach, if Commission Staff had any concerns after review of these compliance filings, it could issue a Report to the Commission expressing its concerns, and, in the appropriate situation, this Commission could open a docket for the purpose of determining whether Ameren violated Section 12-103 of the Public Utilities Act. (220 ILCS 5/12-103). Finally, the process proffered by the AG/CUB is a simple one, and it is one, to which, no party has objected. We therefore conclude that Ameren must follow this procedure." ICC Order on Rehearing Docket No. 07-0539 at 3-4 (March 26, 2008). "This procedure" is described on page 2 of the Plan 1 Order on Rehearing, which states: "The Illinois Attorney General (the "AG") and the Citizens

Utility Board ("CUB") filed a joint response to the Petition for Rehearing, in which, they set forth, with specificity, a procedure, by which, this Commission would have ultimate control over the hiring and firing of the independent evaluator, but, Ameren, and its independent Advisory Committee would be responsible to do the work necessary to hire that evaluator, thereby eliminating the conflict between Section 12-103 of the Public Utilities Act and the Illinois Procurement Code. Both Ameren and Commission Staff filed Replies, in which, they voiced approval of the procedure recommended by the AG and CUB. It is as follows: Ameren, would develop, with input from its stakeholder advisory Committee, a Request for Proposals (an "RFP") to solicit bids for an independent evaluator; Ameren would then file the RFPs as a compliance filing in this docket; Ameren would select, with stakeholder input, an independent evaluator; Ameren would then submit, as a compliance filing in this docket, its contract with the independent evaluator, which would be selected from the firms that responded to the RFP; and This contract must expressly provide that the Commission has the right to: a) approve or reject the contract; b) direct Ameren to terminate the evaluator, if the Commission determines that the evaluator is unable or unwilling to provide an independent evaluation; and c) approve any action by the utility that would result in termination of the evaluator during the term of the contract." ICC Order on Rehearing Docket No. 07-0539 at 2 (March 26, 2008); *see also,* ICC Order Docket No. 10-0568 at 47 (Dec. 21, 2010).

Provision 3: The Plan 2 Order states: "The Commission directs Ameren to continue the activities listed in its Plan to help preserve the independence of the evaluator." ICC Order Docket No. 10-0568 at 69 (Dec. 21, 2010) (emphasis added). The activities listed in AIC's Plan were reproduced on page 46 of the Plan 2 Order: "In addition, during Plan 1, Ameren claims it took the following twelve steps to protect and demonstrate the EM&V evaluator's independence, and plans to continue similar policies during Plan 2: 1. Staff and a stakeholder group facilitator, as well as various consultants for the stakeholders participated in EM&V bid reviews; 2. Staff and a stakeholder group facilitator participated in EM&V consultant interviews and selection; 3. Staff and consultants for various stakeholders reviewed the EM&V consultant's contract and scope of work; 4. Order language specifying the Commission's role was integrated in the EM&V contract; 5. Stakeholder suggestions were incorporated into the EM&V contractor's scope of work; 6. EM&V reports were distributed simultaneously to Staff, stakeholders, and Ameren; 7. Numerous meetings and opportunities were provided for Staff and the stakeholders to review EM&V work plans and provide input into all work plans; 8. Numerous meetings and opportunities were provided for Staff and stakeholders to comment on EM&V results; 9. EM&V consultants presented or participated in numerous stakeholder advisory meetings where Staff was present; 10. Staff was encouraged to have direct communication with the EM&V consultant, and consultants emailed Staff directly several times to provide updates; 11. Staff participated in weekly and bi-weekly conference calls with EM&V consultants and Ameren staff for activity updates. 12. EM&V methods, activities, and results were accepted by Ameren… Ameren argues that these practices are comprehensive and seek to involve parties outside of Ameren in all stages of the EM&V process. By putting the EM&V evaluator in constant contact with the stakeholders and Commission Staff, particularly given the mechanisms for direct Commission oversight, Ameren says it is confident that the current model fully protects EM&V independence." ICC Order Docket No. 10-0568 at 45-46 (Dec. 21, 2010).

Provision 4: The Plan 2 Order states: "The Commission agrees with Staff that Ameren should ensure the data used in the independent evaluations can be made available to the Commission upon request." ICC Order Docket No. 10-0568 at 69 (Dec. 21, 2010) (emphasis added).

Provision 5: The Plan 2 Order states: "Further, Ameren is directed to instruct its evaluation contractor to submit draft EM&V reports to Ameren, the SAG, and Staff concurrently, and directs Ameren to include such a provision in its contract." ICC Order Docket No. 10-0568 at 69 (Dec. 21, 2010) (emphasis added).

Provision 6: The Plan 2 Order states: "In order for the Commission to submit the required energy efficiency related reports to the General Assembly, the Commission agrees with Staff and directs Ameren to file the evaluations and reports required by Section 8-103(f)(7) and 8-104(f)(8) of the Act as they become available via the Commission's e-Docket system in Docket No. 10-0568." ICC Order Docket No. 10-0568 at 68-69 (Dec. 21, 2010) (emphasis added).

Staff provided these detailed provisions to AIC in response to a data request and in turn AIC indicated it opposed certain of these conditions. (Ameren Ex. 6.0, 23-24; Staff Group Cross Ex. 2, 10-14.)

J. Evaluation Cycle

Staff supports the adoption of the same provision the Commission adopted in the Plan 2 Order concerning the evaluation cycle. (Staff Ex. 1.0, 23-24.) The provision from the Plan 2 Order concerning evaluation cycles for which the Commission should reaffirm in this Order is set forth below:

Evaluation Cycle Provision: The Plan 2 Order states: "Ameren currently proposes a modified three-year evaluation cycle that explicitly allows the independent evaluator to conduct less than one impact evaluation and less than one process evaluation every year, with a general goal of conducting one impact evaluation and one process evaluation for each program during each Plan cycle. Staff does not oppose Ameren's proposal subject to several conditions…. The three conditions proposed by Staff, to which Ameren does not object, appear reasonable and they are hereby approved." ICC Order Docket No. 10-0568 at 69 (Dec. 21, 2010) (emphasis added). Ameren's proposal is discussed further on page 48 of the Plan 2 Order: "In response to Intervenors' concerns, Ameren has proposed a modified three-year evaluation cycle that explicitly allows the independent evaluator to conduct less than one impact evaluation and less than one process evaluation every year, with a general goal of conducting one impact evaluation and one process evaluation for each program during each Plan cycle. Further, Ameren says the independent evaluator shall be responsible for developing a 3-year evaluation plan at the beginning of the Plan cycle, for updating this 3-year evaluation plan as necessary to take into account changing market conditions, and for developing evaluation plans for each program. In so doing, Ameren indicates that the independent evaluator should seek advice from Staff, stakeholders and from Ameren, but final plans shall be developed solely at the discretion of the independent evaluator who Ameren claims will also be responsible for managing evaluations to ensure they meet the Commission's approved policies and to ensure that they stay within the Act's spending limitation of 3% of total portfolio costs." ICC Order Docket No. 10-0568 at 48 (Dec. 21, 2010). The three conditions proposed by Staff that the Commission adopted are also described on page 48 of the Plan 2 Order: "Staff does not oppose Ameren's proposal subject to the following three conditions: 1. Ameren should have all program impact evaluations completed at least three months before filing its next energy efficiency plan… 2. Process evaluations should be conducted as early as possible for programs that do not appear to be achieving the gross megawatt-hour savings as forecasted; and 3. Since the independent evaluator is supposed to report its findings to the Commission so that the Commission can make a determination as to whether Ameren has met its energy efficiency standards, the final evaluation plans shall be developed at the discretion of the independent evaluator with agreement from Staff." Id.

AIC opposes certain of these conditions. (Ameren Ex. 6.0, 23-24.) Staff takes issue with AIC's recommendation that Staff be excluded from the evaluation plan development. (Ameren Ex. 6.0, 23:530.) Indeed, Staff was responsible for helping to ensure AIC's evaluator complied with the Plan 2 Order with respect to ensuring differences in evaluation results are not based solely on methodology. (Staff Group Cross Ex. 1, 57, 59, 61.) Despite Commission direction in the Plan 2 Order, Staff has found it extremely difficult to get the Evaluators to use consistent methodologies. (Staff Group Cross Ex. 1, 57-66; Tr. 49, Nov. 20, 2013.) A Commission directive to AIC to require its Evaluators to collaborate with the other utilities' Evaluators to reach consensus on the best approaches to assessing NTG in particular markets for both residential and non-residential EE programs should help alleviate Staff's concerns in this regard.

K. RECOMMENDATION FOR POTENTIAL STUDY

Dr. Brightwell proposed that future feasibility studies include an analysis of economically efficient potential. He prescribed a methodology for obtaining economically efficient potential and described how it differs from economic potential that is traditionally included in feasibility studies. (Staff Ex. 2.0, 21-26.)

The main difference is that economic potential measures how much energy savings is possible when the most energy efficient measure that is cost effective relative to the baseline piece of equipment is installed in all possible cases. Economically efficient potential measures how much energy savings is possible when the last measure that is cost-effective relative to the next most energy efficient piece of equipment is installed in all possible cases. (Staff Ex. 2.0, 21-22.) The economically efficient potential maximizes the net benefits from a measure. In contrast, the economic potential may include savings that, in fact, lower net benefits.

Economic potential answers the question, "What is the potential energy savings from replacing current equipment with the most energy efficient piece of equipment that provides net benefits to customers?" Economically efficient potential answers the question, "What is the potential energy savings if current equipment is replaced with the energy efficient equipment that maximizes net benefits to ratepayers?" (Staff Ex. 2.0, 22.)

Dr. Brightwell provided an explanation for how to conduct an analysis of economically efficient potential and an example using Air Source Heat Pumps. Id. at 22-25.

Among the benefits of economically efficient potential is that it better addresses what is possible when budgets are limited. This occurs because economically efficient potential considers that savings increases are disproportionate to cost increases when moving from one level of energy efficient device to another. Id. at 25.

AIC agreed to provide the suggestion for economically efficient potential to the contractor who will perform the next study and leave it to that contractor to determine if it is appropriate to use it. (Ameren Ex. 6.0, 26.) The Commission should order inclusion of economically efficient potential in the next Potential Study.

VII. MISCELLANEOUS

A. Inclusion of TRM Codes

The Commission should order AIC to include the TRM measures codes associated with the measures included in AIC's Plan filed with the Commission in future plan filings for ease of review. (Staff Ex. 1.0, 27.) This directive is consistent with the Commission-adopted IL-TRM Policy Document. The Company accepted Staff's recommendation in its rebuttal. (Ameren Ex. 6.0, 26.)

B. OTHER

VIII. CONCLUSION

For the reasons set forth above Staff respectfully requests that the Commission's Final Order in the instant proceeding reflect Staff's recommendations consistent with this Initial Brief.

Respectfully submitted,

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